EMERGING NORTH AMERICAN OIL BALANCES:

CONSIDERATIONS RELEVANT TO A TAR SANDS DEVELOPMENT POLICY

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EMERGING NORTH AMERICAN OIL BALANCES: CONSIDERATIONS RELEVANT TO A TAR SANDS DEVELOPMENT POLICY

SUMMARY

1. This Report is intended to provide an appreciation of the external factors that will be relevant to Alberta Government review of Tar Sands Policy. The focus is on both economic trends and directions in Canadian and U.S. public policies which will bear upon the prospects for the development of Alberta's tar sands resources.

North American Oil Balances

2. Emerging North American oil balances are generally quite favorable for tar sands development. On the Canadian side, unless the rate of finding new reserves increases substantially, the outlook is for production of conventional Western Canadian oil to peak out sometime in the latter 1970's. If Western Canada's conventional oil reserves alone must provide an assured supply to meet future Canadian oil requirements, Canada's export potential could disappear by the early 1980's, if not sooner. Canada's frontier areas may eventually yield substantial new oil production, but so far the major discoveries in the Arctic are of natural gas, with oil a more distant prospect. Against this outlook, the establishment of early and substantial volumes of tar sands production could play a vital role in providing reserves needed to assure future Canadian requirements and maintain Canada's oil export potential. This picture represents a complete turnaround from that of a few years ago, when the concern was that tar sands production would impinge on rates of utilization of conventional Western Canadian crude oil reserves.

3. In the short run (i.e., through 1980 or so), the United States faces a very substantial shortfall between oil requirements and availability of domestic production. U.S. oil imports will be increasing sharply and will meet a much larger share of U.S. oil requirements than at present. By 1980, the level of U.S. oil imports will be upwards of 7 1/2 million barrels daily and perhaps as high as 13 million barrels per day.

4. Over the long run (i.e., beyond the mid-1980's), there is much greater uncertainty as to how large U.S. oil import requirements will be. By then, U.S. policies directed at the development of indigenous resources and conservation in the use of energy could have a substantial impact on import volumes. The biggest question marks are how successful exploration may be in frontier areas -- e.g., in Alaska, offshore, and deeper producing horizons in established areas -- and the pace and scale of development of synthetic oil production from U.S. shale and coal reserves.

5. What happens in the interim -- i.e., after the short-run period in which large increases in imports look almost inevitable and before the long run in which there are major areas of uncertainty -- will depend largely on the timing of events. The rapid development of major new domestic supplies -- e.g., the early discovery of several new "Prudhoe Bays" or the opening up of a major new producing province offshore -- could cut back the growth in imports by the early 1980's. On the other hand, if expanded U.S. exploration is not successful early on, the period of rapidly rising oil imports could continue on into the mid-1980's.

6. Thus, trends in North American oil balances point to a large potential market for tar sands oil production. The tar sands could provide Canada with oil supplies needed to assure future domestic needs. To the extent that Canada can maintain an export potential -- something to which tar sands oil could make a major contribution -- Canadian oil will find a large and expanding market in the United States for many years to come. The only thing that could really change this outlook would be the simultaneous development of a number of other major new sources of North American oil at a relatively early date.

Competitive Crude Oil Values

7. Future trends in competitive crude oil prices also look favorable for tar sands development. The terms and conditions under which foreign oil will be available to meet North American oil import requirements will bear upon both trends in North American crude oil prices and the formulation of U.S. and Canadian oil policies. As the major source of incremental volumes to meet world oil requirements, the Middle East will play a pivotal role in foreign oil. The costs of Middle East oil will be the basis of competitive price/cost relationships in world oil markets and the Middle East will serve as the political fulcrum for changing concessionary arrangements in producing/exporting countries.

8. From the physical standpoint, foreign oil resources are more than adequate to meet requirements over the decade. As in the past, the upward pressure on foreign oil prices will come primarily from escalating "take" by producing governments. The going market price for light Persian Gulf crude oil increased from approximately $1.30 per barrel in mid-1970 to a price now being quoted for 1973 deliveries of around $2.15, or an increase of some 85 cents, largely reflecting sharp increases in royalty/tax payments and the added "cost" of buying back the governments' share of oil under "participation." While the costs and conditions under which Middle East crude will be produced are very uncertain for the future, further increases in the price of Middle East oil could be on the order of $2 per barrel or more between now and 1980. Beyond 1980, foreign oil prices will be pointed still higher with uncertainties over physical availability of supplies probably adding to the pressure on prices.

9. The escalating costs of foreign oil would in any case set a floor under pricing of U.S. crude oil supplies. Over the long run, the real question is whether the volume and cost of North American energy resources will set a ceiling on what the United States has to pay for its oil supplies. In the interim, the United States will probably be willing to continue paying some premium for U.S. and Canadian oil over and above the cost of foreign oil -- if required to support a viable North American oil industry and provide adequate incentives for continuing exploration and for development of synthetic production. As with foreign oil prices, all this is almost impossible to quantify with any degree of accuracy. However, as a working hypothesis, what we may be looking at is a trend in U.S. prices pointing in the direction of $5 per barrel crude oil for the period under consideration. This trend could be tempered somewhat by early, large-scale development of domestic resources at favorable costs -- but this is not likely before the 1980's at least. On the other hand, the trend could be accelerated, reaching this target sooner than 1980 and perhaps going above it, if domestic finding results are disappointing and foreign oil prices escalate very rapidly.

10. For the future, one would expect reasonable alignment of Canadian crude prices with U.S. prices on shipments to U.S. markets. From the U.S. standpoint, Canadian export prices provide incentives for development of Canadian oil resources for export. Canada would have an obvious interest in seeing its oil exports realize prices in U.S. markets in line with U.S. crude prices. However, there may be objections within Canada to paying higher prices for Canadian oil which reflect primarily intensified demand in U.S. markets rather than the pressure of Canadian resource costs. Thus, Canada might consider some type of two-price system, with lower prices for the domestic market. Whether Canada would opt for a two-price system would depend in part on how the benefits of low-cost energy for Canadian consumers and industry are weighed against higher realizations for

producers and hence incentives for development of Canadian resources. In any event, the value of future tar sands production stands to benefit very significantly from the upward push of foreign oil prices and the upward pull of U. S. oil prices required to provide incentives to North American resource development -- although what the push will be or the pull has to be are really not predictable.

Directions in Public Policy

U. S. Policy Issues

11. U.S. concern over security of imported oil supplies has obviously been heightened by recent developments in foreign oil. Looking ahead, the picture is one of rapidly increasing prices for increasingly insecure foreign oil supplies. It is not only that foreign producing areas are insecure, but the rising proportion of U. S. oil supplies that must be drawn from these sources makes the problem that much greater. In the short run, there is relatively little the United States can do to mitigate potential supply problems, aside from measures to stockpile larger inventories of oil.

12. For the longer run, however, the United States has the opportunity to bolster the security of its oil supplies -- and more broadly, its energy supplies -- through policies designed to affect overall domestic supply/demand balances and the availability of import streams from secure sources. Policies directed at providing incentives for development of North American resources -- conventional oil and gas, synthetics, and nuclear power -- would be a major part of this long-run effort.

13. Where the delivered price of foreign oil is below domestic costs, the United States will probably continue to maintain quantitative controls on imports. In the short run, oil import volumes will have to be set at levels necessary to supplement current domestic availability. Over the longer run, oil import volumes would be progressively adjusted according to trends in domestic availability, considering reasonable rates of production from domestic reserves and taking account of such standby capacity as is deemed desirable from a security standpoint. On this basis, the long-run trend in U. S. crude oil prices could be expected to reflect emerging domestic costs of finding, developing, and transportation, including return for risks of investment. The contribution of import policy to exploration incentives would thus be assurance of domestic markets and prospects for remunerative prices.

14. The concerns of U.S. policy go well beyond the question of security of oil supplies to encompass a broader range of energy issues. The United States has built up very large potential demand for gas by pricing gas low as compared with other energy fuels in the past. But this does not necessarily mean that future policy has to be framed in such a way as to ensure that all this potential demand is met at whatever the cost. There are substantial opportunities for substitution of oil for gas in under-the-boiler uses. To the extent energy must be imported, crude oil would potentially offer a lower cost and a no less secure alternative than LNG or SNG.

15. If U.S. energy and import policy is framed in such a way as to allow oil to meet energy needs that would otherwise be met by gas, the demand for and price pressures on gas may be less than currently being projected. The corollary is that the demand for and price pressures on oil may be greater than now anticipated.

16. If oil plays a larger role in meeting U.S. energy needs, Canadian oil could make an important contribution not only as a refinery feedstock, but also as a significant source of clean fuel in competitive energy markets. Oil produced from the tar sands could be particularly valuable. A low-sulphur content should make various fractions from tar sands oil -- or even the whole synthetic crude -- desirable products for burning. An unusually large fraction of synthetic tar sands crude is in the distillate range. Trends in distillate demand and prices are likely to make this fraction increasingly valuable to U.S. refiners over the years ahead.

17. Future directions in U.S. policy are thus clearly quite favorable for the outlook for potential Canadian oil exports. U.S. policy is certain to recognize a substantially larger volume of Canadian oil as an essential supplement to domestic production. While Canadian crude oil imports into East-of-the-Rockies market are still subject to quota, indications are that formal restrictions may be lifted -- or at least very substantially liberalized -- in the near future. For the years immediately ahead, demand for Canadian crude by U.S. refiners is expected to be very strong -- almost irrespective of price. Thus, the level of Canadian oil exports to the United States in the near term will be basically a function of the ability and willingness of Canada to deliver.

18. Looking to the longer run, Canadian oil should continue to be a preferred source of U.S. oil imports. As with domestic oil, it is also in the long-run interest of U.S. policy to provide markets and remunerative prices for Canadian oil supplies. Canadian oil will contribute importantly to U.S. balances and higher Canadian prices for Canadian oil will, in course, favor intensified exploration and the development of synthetic production, as in the United States. The United States will probably be interested in importing as much oil as Canada makes available at least through the early 1980's, but one cannot rule out the possibility that the establishment of major new U.S. production from frontier areas could have an impact on U.S. oil imports from Canada near the end of this period -- at least a significant impact on increases from year to year.

19. As yet, the United States does not really have a comprehensive policy for development of synthetic oil production from its own vast reserves of shale and coal. But the United States is likely to recognize development of these resources as essential to the long-run security of its energy supplies and adopt policies designed to encourage this development. However, this should not diminish U.S. interest in tar sands development. The future demand of the United States for secure sources of oil is so large that the United States will look to all potentially available North American resources in due course. Furthermore, tar sands would appear to hold out the potential at least of development of larger volumes of production at an earlier date and with somewhat less uncertainty than either U.S. oil shale or coal liquefaction. This should be of considerable importance to the United States.

Canadian Policy Issues

20. The concerns of Canadian oil policies are shifting with the changing circumstances of the Canadian oil industry. In the past, the problem has been one of finding adequate markets for Canadian oil resources. At least for the years immediately ahead, the problem will shift to one of meeting all the demands upon Canadian reserves and controlling the volume of oil exports in order to assure supplies for the domestic market.

21. Whatever the exact form Canadian oil export controls might take, a firm program for tar sands development could change very significantly the future supply picture that the NEB would be looking at in establishing export volumes. Tar sands projects could provide reserves and production needed to assure future Canadian requirements. On this basis, a tar sands

development program could serve to take considerable pressure off conventional Western Canadian oil to hold reserves for future domestic needs and might actually contribute to higher rates of utilization of conventional reserves.

22. A longer-run Canadian policy issue is the extent to which the Nation should develop its own oil and gas resources for export markets. In the past, the desirability of resource development had been accepted almost without question, but now this issue has become subject to increasingly sharp debate. Opponents of maximum resource development argue that such efforts are not necessary to meet Canada's own requirements and pose serious problems for Canada -- e.g., environmental damage, distortions in foreign exchange and financial markets, and increased control by U.S. firms over the Canadian economy. Against these negative aspects, the potential benefits to Canadian citizens in terms of employment opportunities, governmental revenues, and collateral industrial development are seen by the opponents of resource development as comparatively modest.

23. It is not our remit to assess the merits of the case for or against resource development for export. In the context of the debate, however, tar sands projects would presumably meet the criteria of Canada's interests -- as well as the interests of the Province of Alberta -- at least as well and probably rather better than Arctic oil and gas development. Environmental problems would certainly not appear to be more difficult. Tar sands could offer opportunities for employment and collateral industrial development that compare favorably with conventional oil and gas production, especially Arctic production.

24. From the standpoint of both U.S. and Canadian policies discussed above, there is an advantage to moving early and rapidly to develop tar sands production. For the United States, early development of the tar sands could contribute to the availability of secure North American oil supplies over the critical period before its own long-run efforts to develop conventional and synthetic oil might begin to pay off. For Canada, the establishment of early and substantial volumes of tar sands production could be essential to maintenance of Canada's export potential, providing an offset to Canada's rising volumes of oil imports. For both the United States and Canada, rapid tar sands development would provide "third-generation" plants by the latter 1980's or so and an earlier fix on the long-run cost of North American synthetic oil production.

25. While this is a strategic time to push ahead with tar sands development, there is always the possibility that large-scale production from the tar sands could result in less-than-optimum utilization of conventional Alberta oil at some time in the future -- e.g., if major oil production is established in the Mackenzie Delta and/or the Arctic Islands. However, this is a development that obviously cannot be predicted. Furthermore, in view of the overall outlook for North American oil balances, the impact of tar sands production on conventional Alberta oil would probably be relatively limited in degree and duration-- if it were to have an impact at all.

Implications for Tar Sands Development

26. Tar sands technology is still in the relatively early stages of development and experience with commercial-scale operations is limited. The costs of alternative approaches and technologies will not really be known until they are tried on a commercial scale. Thus, the experience of a number of initial approaches could be important to the success of second-generation projects.

27. Costs will also obviously bear upon Provincial royalties. In the short run, high costs may pose problems of setting royalties that do not unduly burden the economics of initial plants. Over the long run, with the emergence of a more stable and predictable cost basis, costs will be a major factor in the determination of a royalty policy that optimizes the Province's economic interest in some 350 billion barrels of recoverable tar sands oil reserves, which the Province could make available to meet North American oil requirements.

28. In principle, a royalty policy should meet two broad criteria. On the one hand, after payment of royalty, producers should still have reasonable incentives to construct and operate tar sands facilities. On the other, the Province, as owner of the tar sands, should receive a payment that reasonably reflects the value of the resource. However, in view of the present stage of tar sands development and the uncertainties over future costs and prices, it would seem virtually impossible to establish a royalty now that would be equitable to both producers and the Province for all future tar sands projects or even for the remaining life of the project now in operation.

29. Two approaches might be considered to the establishment of interim royalties. One would be to set royalties for early plants on a project-by-project basis, depending upon technical specifications and cost projections. These interim royalties would apply for a given number of years and then would be subject to review in the light of longer-run royalty policy. Another approach to the setting of interim royalties might be to establish a general royalty that would be relatively attractive to producers and which would apply to all production prior to a certain date. This could provide an incentive to early tar sands development, since the benefits to an individual project would depend upon how many years it came into production before the cut-off date. Under any type of interim royalty arrangements, of course, there would also have to be a reasonable degree of assurance that longer-run royalties would not be set in the range that would impinge on the viability of projects after the investment has been made. Thus, it would be essential to set out at least some general principles governing longer-term royalties at the outset.

30. The question of how to determine the value on which tar sands royalties should be assessed is a difficult one. In principle, the value of raw bitumen extracted from the sands would appear to be the appropriate concept. However, barring the development of a commercial market for raw bitumen, the value of bitumen can only be established by reference to the market value of the final products that move out of a tar sands facility, with allowance for the costs of processing or upgrading. Once the tar sands industry has developed and there is a reasonable body of experience to draw upon, average processing costs (including reasonable return on investment) would be the appropriate concept to apply in netting back the market value of final products to the bitumen level. Over the long run, it will be average costs that in fact determine how much bitumen is worth, not the uniquely high or low costs of any particular facility. The Province will want a long-run royalty that reflects the general value of the resource, not the particular economic circumstances -- good or bad -- of individual projects.

31. In view of the different nature of conventional oil versus tar sands operations, relationships between prices or values and costs may also be quite different. As a result, the potential impact of a given royalty rate on the economics of tar sands production may also be very different from the impact on conventional crude. Thus, royalty rates on conventional crude must be used with considerable caution as guidelines to an appropriate tar sands royalty.

32. To the extent that the emerging environment is as discussed earlier and U.S. and Canadian Federal policies are conducive to tar sands development, problems of financing would not look to be intractable. While tar sands will require very large outlays at a time when the industry will face huge capital demands in other areas also, tar sands development is not at the bottom of the list of priorities by any means. While the problem of financing cannot be passed off lightly, it does not look like something that should be the single most important criterion in a tar sands policy.

33. In general, major integrated oil companies -- i.e., large-scale companies which have interests in both oil resources and refining/marketing -- would have a considerable incentive to participate in the development of the tar sands. All of these companies have a basic interest in a strong resource position to support their heavy investment in downstream operations. As control over reserves becomes less certain in foreign areas and their status as privileged offtakers is eroded, the majors are likely to be increasingly interested in access to North American reserves to meet their North American crude requirements. North American oil will move into North American refineries -- as a matter of governmental policy if not of free-market economics. If the majors have to process North American oil in their facilities, they would rather be the producers of that oil than have to purchase it from others.

34. Various Canadian independents will also be interested in participating in tar sands development. Their interest in tar sands has already been evidenced by the acquisition of permit acreage. Technical and financial limitations could make it difficult for Canadian independents to enter commercial tar sands operations on their own. Even combinations of a number of independents could face similar problems. However, the independents could participate as members of broader corporate groupings which might include major integrated companies who would provide the required technical expertise. Smaller-scale participations would probably be within the financial capabilities of various independents. Major company participants might also contract for the output of the independents, providing assured markets.

35. Various national companies of oil-importing countries -- notably from Western Europe and Japan -- may also have an interest in tar sands development. While it would seem unlikely that these companies would

be interested in actually moving tar sands oil to their home markets (except perhaps to Japan), investment in tar sands development does hold out the prospect of "financial diversification" of oil resources. National companies and their home governments are concerned with the prospect of physical cut-off of supplies, but they are also concerned with the costs of their oil supplies -- both from the standpoint of import costs to the country and the competitive capabilities of the national companies. Tar sands production could provide a national company with a financial hedge against rising oil costs in other areas, notably in OPEC countries. Increasing prices for their tar sands oil in the high-value North American market could be a significant offset to higher costs and prices elsewhere. Furthermore, European countries have been concerned that the upstream profitability of the major international oil companies gives them a big advantage in competing downstream with European refining and marketing companies. Tar sands development could give European companies a foothold in North American production, bolstering their competitive abilities even in home markets.

36. From the standpoint of the Province of Alberta, emerging North American oil balances and the likely directions of public policy in the United States and Canada point to a very real advantage in moving ahead rapidly with tar sands development. The tar sands have already established an early lead over other North American synthetics in the development of technology and in experience with commercial-scale operations. Pushing ahead now could serve to maintain and perhaps even increase this lead. Alberta probably has the opportunity of developing second-generation plants by the time first-generation U.S. oil shale and coal liquefaction plants are coming onstream. And third-generation tar sands plants, which could be expected to benefit from relatively well established technology and perhaps important cost-savings, might be onstream by the time these other synthetics are in a second-round phase of development.

37. Early development of the tar sands could also be very important in establishing a "base-load" position for tar sands production. With the very large capital outlays required for construction of tar sands facilities, high rates of capacity utilization are essential to achieve reasonably low unit costs of production. Thus, the economics of tar sands operations virtually require that they supply a base load. In view of the contribution that tar sands production is capable of making to North American oil availability at a critical time, special treatment for tar sands projects could be warranted under Canadian and U.S. policies. The participants in tar sands

development would themselves seek to ensure the viability of their ventures by concluding long-term arrangements for disposal of output. Government policy would probably recognize such arrangements as having the attributes of a base load. In the event Arctic oil moves in later in large volumes, such oil may also achieve a preferred status, but the treatment might not be quite the same as for tar sands projects coming onstream earlier.

38. While the future environment looks to favor building up tar sands production rapidly, there are obviously practical limits on the number and scale of projects and on how fast they can be designed and constructed. Ongoing research into alternative techniques may take some years until the stage is reached when decisions can be made to move ahead on commercial ventures. Furthermore, there may be limits on the capacity of the engineering-construction industry to design and construct new facilities. If a decision is made to move ahead on tar sands development, Alberta policy can only encourage further projects. Policy cannot push development at an unrealistic pace. Even if this were possible, the long-run results could be detrimental if it led to ill-conceived and hastily designed and constructed projects.

39. Regardless of the pace of development, there would seem to be a real advantage to Alberta in encouraging diversification in tar sands efforts -- with regard to technology, numbers of participants, and in the mix of types of participants.

40. At this early stage, there is no way of knowing just what approach or approaches will turn out to be the most attractive methods of producing tar sands oil. Thus, over the long run, tar sands technology is likely to develop more rapidly and with better results if a wide range of alternatives is explored at the very beginning. To this end, Alberta policy should encourage a wide range of research and development efforts using differing technologies.

41. Diversification in the number of participants is also likely to serve the interests of Alberta. Within limits, more participants could broaden the scope of approaches undertaken, add to the financial reserves

available for development, and widen the range of potential markets for tar sands oil. Domination of tar sands development by a few companies could have the opposite effects. For the same reasons, diversification in the mix of participants would also look in the best interests of the Province. Alberta is likely to benefit from participation not only by major integrated companies, but also by independents and foreign companies as well.

42. From the standpoint of the Province of Alberta, prospective participants in tar sands development would ideally possess technical competence, financial capability, and marketing ability to ensure disposition of production. The major integrated companies would generally qualify on all of the above counts. For Canada, these companies do represent foreign ownership. The Canadian Federal Government and the Province of Alberta may wish to consider foreign versus Canadian participation as one of the criteria for tar sands development. However, this is an issue on which we cannot really provide a judgment.

43. The Canadian independents have experience primarily in conventional oil and gas exploration. But this would not really be an impediment to participation in a larger group where at least one or more of the other participants has the technical competence. Much the same would be true for financing as well. Canadian independents could be in a position to finance smaller-scale interests, particularly where they are partners with major integrated companies who provide the technical competitive and perhaps guaranteed market outlets.

44. However, the independents need not necessarily be dependent on major-company participants for market outlets. Various U.S. refining companies who do not participate directly in tar sands development would probably be prepared to negotiate armslength deals for tar sands supplies on a long-term basis. Sales by independents could open up a range of competitive marketing that might otherwise be foreclosed if major companies are the only developers of the tar sands. This could serve to broaden the market for tar sands oil and prices on third-party sales could provide an important element to the valuation of tar sands oil for royalty purposes.

45. Foreign companies wishing to participate in tar sands development could also make an important contribution. Most of these companies have very considerable experience in large-scale processing, both in refining and petrochemicals. If they make a decision to participate in the tar sands, these companies would also have the financial capabilities, with some type of backing provided by their home governments. Lacking a North American refining/marketing position, they would also have to look to offtake by major-company participants or armslength sales. However, these companies may also have opportunities for exchanging tar sands oil in North America for foreign oil elsewhere to meet their refining requirements abroad.

46. In sum, it appears likely that tar sands production will find market outlets up to the practical limits on development through the mid-1980's at least. It would look to be in the interest of the Province to get projects underway as rapidly as possible, in order to take advantage of the opportunities open to the tar sands over this period. In selecting projects, the Province should benefit over the long run from a policy aimed at a reasonable diversity of approaches and participants. Diversification of efforts should serve to advance the development of tar sands technology more rapidly and could broaden the basis of marketing of tar sands oil.

47. Alberta's huge tar sands resources offer a unique opportunity for the establishment of a major new industry, which could make a very valuable contribution both to North American oil requirements and to the Province itself. In setting a new long-range tar sands development policy, the Government of Alberta can play a very vital role in seeing that this opportunity is realized.

EMERGING NORTH AMERICAN OIL BALANCES: CONSIDERATIONS RELEVANT TO A TAR SANDS DEVELOPMENT POLICY

Introduction

1. This Report is intended to provide an appreciation of the external factors that will be relevant to Alberta Government review of Tar Sands Policy. The focus is on both economic trends and directions in Canadian and U.S. public policies which will bear upon the prospects for the development of Alberta's tar sands resources.

2. The Report is organized into four sections:

I. North American Oil Balances. This section considers trends in U.S. and Canadian oil demand and supply, as these will bear upon potential markets for tar sands oil.

II. Competitive Crude Oil Values. This section reviews the major factors bearing on competitive crude oil values in North America over the years ahead.

III. Directions in Public Policy. This section looks at basic directions in U.S. and Canadian policy which will affect the development and marketing of tar sands oil.

IV. Implications for Tar Sands Development. This concluding section considers the implications of the various external factors reviewed in preceding sections for potential interest in tar sands development and a Provincial policy for the tar sands.

I. NORTH AMERICAN OIL BALANCES

1. Future North American oil demand and supply balances will clearly be an important consideration for the Alberta Government's Tar Sands Policy for the years ahead. An increasing gap between North American oil requirements and indigenous oil production will provide the potential market for tar sands oil. The prices that will bring North American oil requirements and supplies into balance will bear importantly on the competitive value of tar sands oil. Both North American oil balances and prices will be key factors for the economic attractiveness of tar sands operations, on the one hand, and the royalty income and other advantages that the Province of Alberta might realize from development of its tar sands resources.

2. At present, oil requirements in Eastern Canada are supplied by imports from offshore sources. Western Canadian production supplies domestic requirements West of the Ottawa Valley, but the larger part of production moves to export markets in the United States. Looking ahead, if conventional oil from the Western Canadian provinces alone is to assure adequate reserves to meet future Western Canadian requirements, there is a real question as to Canada's future export potential. Tar sands development would not look to be essential to meet Canada's domestic requirements for some time ahead, assuming continued free importation into Eastern Canada. However, the establishment of early and substantial volumes of tar sands production could contribute very importantly to maintenance of Canada's oil export potential, providing an offset to Canada's oil imports. Tar sands development would also provide continuing investment in resource development, with associated economic benefits for Canada.

Canadian Oil Requirements and Supplies

3. In 1972, total demand for petroleum products in Canada averaged about 1.6 million barrels daily. Demand in Eastern Canada was largely met by the output of local refineries operating on imported crude oil, supplemented by small volumes of imports of refined products. In 1972, imports of foreign crude oil into Eastern Canada came to around 800,000 barrels per day.

4. Western Canadian production of crude oil and equivalents in 1972 averaged about 1.7 million barrels daily.* Of this total, about 750,000 barrels per day moved into Canadian refineries from British Columbia eastward to Toronto. The larger part -- 935,000 barrels daily -- moved into export markets in the United States, some 660,000 barrels per day into East-of-the-Rockies refineries from Montana to Buffalo and 275,000 barrels daily into Puget Sound on the West Coast.

5. Looking ahead, the demand for crude by Canadian refineries operating on Canadian supplies is projected to increase from 750,000 barrels per day in 1972 to around 1.0 million barrels daily in 1980 and then reaching perhaps 1.2 million by 1985. Barring a major shift in Canadian oil policy, these future requirements will have to be met by Canadian resources.

6. Recent years have witnessed a tremendous impetus to exploration in frontier areas -- the Mackenzie Delta, Arctic Islands, and offshore East Coast -- and a reduction in activity in the established producing areas of Western Canada. So far, however, it is natural gas that has emerged as the basic energy resource in frontier areas. In the Mackenzie Delta and Arctic Islands, large-scale gas reserves have been established and a push is on to find enough added reserves to support investment in pipelines to move gas to markets. While there have also been oil finds in the Mackenzie Delta, as of now oil reserves do not appear to be nearly as important as gas reserves. Indications are that natural gas will be moving out of the Delta earlier than oil. Success offshore Eastern Canada to date has been relatively limited. In any event, if commercial oil production is established offshore, this oil would probably displace foreign oil in Eastern Canadian markets. Thus, despite major exploration efforts in frontier areas, it looks like the Western Canadian provinces will have to assure oil supplies for domestic refineries West of the Ottawa Valley for at least some years to come.

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* Of this total, some 1.5 million barrels per day was conventional crude oil, 150,000 barrels daily pentanes plus/condensates and 50,000 barrels per day synthetic crude from tar sands. In addition, production of LPG's from gas-processing plants was 130,000 barrels daily.

7. Proved reserves of crude oil in Western Canada are about 8 billion barrels, representing about 15 years at current rates of production; Alberta reserves some 7 billion barrels, or 17 years production. Remaining proved reserves in Western Canada have declined somewhat since 1969, reflecting both stepped-up levels of production and a decline in the rate of finding of new reserves. Despite the shift in the focus of exploration to frontier areas, Western Canada still remains a relatively lightly explored area by North American standards and one in which the prospects are still good for finding reserves at reasonable costs. To the extent that the major companies tend to move to the frontiers, the opportunities for Canadian independents in particular may be quite attractive in Alberta and the other Western Canadian provinces.

8. However, as ample as reserves look now and with prospects still favorable for future discoveries, the Western Canadian conventional crude oil resource base is not limitless. If the rate of finding new reserves continues at about the rate of the last decade or so, the outlook is for production to peak out sometime in the latter 1970's. Further, if Western Canada's conventional crude oil reserves are to provide an assured supply to meet future Canadian oil requirements, Western Canada's export potential could disappear by the early 1980's, if not sooner.

9. Thus, Canada's ability to maintain an oil export potential over the long run depends upon either substantial new oil discoveries in frontier areas or a program of stepped-up and accelerated development of tar sands production. This picture represents a turn-around from that of a few years ago, when the concern was that tar sands production would impinge on rates of utilization of conventional crude oil, notably in Alberta. For the future, the development of the tar sands could provide reserves needed to assure future domestic requirements and contribute importantly to the maintenance of Canada's export potential. Furthermore, to the extent that some of the pressure to hold reserves for future domestic needs is taken off conventional crude, Alberta production of crude oil may be able to operate at higher rates of utilization of reserves.

10. All this is of tremendous significance for the United States. As will be discussed, the United States faces sharply rising oil import requirements. At least in the short run, a large part of these requirements will have to come from Eastern Hemisphere sources, notably the Middle East,

raising serious questions of supply security. Just how large the security problem is and how long it remains a problem depends in part on the volumes of production that Canada can make available to the United States. Over the long run, the political and concessionary uncertainties in the Middle East and other major foreign producing areas will bear not only on the volumes of oil (and gas) that the United States will want from Canada but also on the prices the United States will be prepared to pay for North American resources.

U.S. Oil Requirements and Supplies

11. There are many projections of future U.S. oil balances and it is not our purpose in this Report to develop yet another set of projections. Our approach is rather to review the range of responsible government and industry data, with particular emphasis on areas of uncertainty that may be important to the market prospects for tar sands oil.*

Demand

12. In 1972, U.S. domestic demand for petroleum products was some 16 million barrels daily. Projections for 1980 generally range from approximately 20 to 25 million barrels per day. By 1985, demand is projected to reach 23 to 30 million barrels daily. Varying assumptions as to growth in total U.S. energy requirements account for some of the differences among demand projections. More important are varying assumptions as to the role of oil versus other energy sources in meeting energy needs.

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* Appendix A -- U.S. Oil Requirements and Supplies -- sets out a detailed discussion of U.S. oil balances through 1980 and 1985. The Appendix reviews a number of recent projections made by oil companies, trade associations, banks and U.S. and Canadian Government agencies. It considers various problems of comparing projections and focuses on the underlying assumptions behind the projections which account for significant differences among them. The text above only summarizes briefly the range of projections and then moves quickly to major conclusions.

13. Higher projections of U.S. oil demand tend to assume that oil will meet a relatively large share of increased U.S. energy requirements. In particular, oil is projected to meet a substantial energy market that would have been met by gas, absent limitations on gas availability and very much higher than current prices for incremental gas supplies. Just how much substitution there will be of oil for gas in the U.S. energy economy will depend importantly on the relative prices of the two energy sources over the year ahead. Relative oil and gas prices in the United States will be determined not only by domestic resource availability but also by public policy, since imported oil and gas will have to provide the bulk of incremental supplies to meet energy requirements. It would be imported oil that would directly supplement if not supplant natural gas in various interchangeable markets or be used indirectly as a feedstock to manufacture gas in the United States; incremental gas supplies, over and above additional quantities of natural gas from Canada, would be imported LNG.

14. In any event, the United States will have to increase its total energy imports substantially. From the standpoint of both cost and security of supply, importation of crude oil would look to have considerable advantage over importation of either liquefied natural gas or liquid feedstocks for manufacture of substitute natural gas. Thus, the basic realities that will bear on U.S. policies over the long run would appear to point toward oil directly meeting substantial energy needs that might otherwise be met by gas, both through larger oil imports and higher gas prices.* In the event policy goes this way, the trend would be towards higher rather than lower future oil requirements. We return in Section III to a closer look at future U.S. energy and import policies.

15. In the face of increasingly difficult energy balances in the United States, consideration has been given recently to possibilities for instituting various measures that would either improve on the efficiency with which energy is utilized or minimize the consumption of energy. In a society increasingly concerned with ecology and environmental protection, there is little doubt that certain energy-conservation measures will be adopted.** However, many of the measures that might significantly reduce energy

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* In this context also, relative price trends would seem to favor oil products and fractions that enter into end uses where they directly supplement or supplant natural gas, which is of considerable relevance to the valuation of tar sands oil (of which more in Section III).

** It is important to note that concern with ecology and environmental protection also works in the direction of higher energy use, since many measures designed to protect the environment themselves require substantial volumes of energy.

consumption would probably require restrictive regulations and/or tax incentives (either credits or penalties) to implement. And it is not at all clear that the U.S. public will accept or impel very drastic steps in these directions, particularly if it is felt that adequate energy supplies are likely to be available at prices that while higher than at present are still not unreasonable.

16. As a result, most projections assume that measures aimed at conservation of energy will have only a comparatively minor impact on oil consumption, particularly through 1980. However, the further one looks into the future, the greater the chances are that there may be increased rationalization and conservation in the use of energy. Furthermore, the more rapidly demand for energy grows relative to availability, the higher energy prices are likely to be and the more prices themselves will act as an energy conservation measure.

17. In sum, through 1980 or into the early 1980's, growth in U.S. oil demand is likely to be relatively rapid. Looking further ahead, the pace of growth in demand may well slow down, depending upon policy decisions with regard to energy conservation that really have not been taken as yet.

Production

18. Against the rising trend in oil requirements, U.S. oil production is expected to show only relatively modest growth at best and probably a decline from current levels. Excluding Alaska's North Slope, U.S. proven reserves of crude oil have been declining since 1966 and currently represent only about 9 years production.* Productive capacity in the United States has been declining since 1968.

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* Even including the 9.6 billion barrels of reserves estimated for the Permo-Triassic reservoir at Prudhoe Bay, the U.S. reserve-to-production ratio is only 12 years.

19. In 1972, U.S. crude and NGL production averaged about 11 million barrels daily. Production for 1980 is projected in a range from 9 million barrels per day (a decline of 2 million) to 14 million barrels daily (an increase of 3 million). Projections for 1985 range from 10 to 15 million barrels per day.

20. Most projections of U.S. oil production assume (i) production from Alaska's North Slope of about 2.0 million barrels daily (approximately the capacity of the planned Alyeska line to south Alaska) in 1980, rising to some 2 1/2 to 3 million barrels per day in 1985; and (ii) relatively modest volumes of synthetic production from oil shale and/or coal, generally not exceeding 500,000 barrels daily or so even by 1985.

21. The major differences among projections are owing to assumptions as to production from reserves that will be found in the future. In general, higher projections tend to assume a relatively favorable economic and political environment for U.S. resource development, stepped-up levels of exploratory activity, and reasonably good results from the exploratory effort. Lower projections tend to assume a less favorable climate (e.g., only limited increases in U.S. crude prices, continued environmental delays, uncertainties under U.S. oil import policy, etc.), no really significant increase in exploration, and less favorable returns to exploration efforts.

22. Putting it all together, what comes out is a relatively rapid increase in U.S. oil requirements as a component of total energy demand and lagging domestic oil production, apart from the specific timing of North Slope crude. This points clearly to a rising trend in U.S. oil import requirements.

Net Import Requirements

23. In 1972, total U.S. oil imports -- including both crude oil and petroleum products (largely residual fuel oil) -- came to some 4.7 million barrels per day. Projections of U.S. net import requirements -- i.e., the difference between projected domestic demand and domestic production -- generally range from 7 1/2 million to 13 million barrels daily by 1980, an

increase of 3 to 8 million barrels per day over the level of 1972.* As a percentage of total domestic demand, imports would increase from 29 per cent in 1972 to 37-54 per cent by 1980.

24. Reflecting greater uncertainties on both the demand and supply side, projections of imports in 1985 cover an even wider range from 8 1/2 to 19 million barrels daily, or 38-66 per cent of total oil demand.

25. Future U.S. energy and import policies will play a key role in determining levels of U.S. oil imports over the years ahead -- bearing importantly on both oil demand and supply. The highest projections of U.S. oil imports would probably be realized only in the event the United States fails to take significant steps to deal with its energy problems and present trends continued essentially uninterrupted. However, in view of the high degree of current concern with energy problems in the United States -- including within government -- this would seem relatively unlikely. On the other hand, very low levels of U.S. oil imports could probably be achieved only through early adoption of very aggressive policies to spur development of domestic resources of all kinds -- including conventional oil and gas, coal gasification and liquefaction, oil shale, and nuclear power. However, even if these policies were to be pressed, it would still take very considerable time before they could be effective in adding substantially to U.S. energy supplies. Over the period through 1980 or so, U.S. policies directed at development of indigenous resources and/or energy conservation are likely only to have a moderate impact on import volumes.

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* This range excludes two extreme projections made by the U.S. National Petroleum Council (NPC). Under the NPC's Case I -- which assumes a maximum effort to develop all domestic fuel sources -- net imports in 1980 are projected at 5.8 million barrels daily. This Case is characterized by the NPC as "difficult to attain." NPC Case IV -- which makes very pessimistic assumptions as to environmental constraints to resource development, inhibiting government policies, and relatively unfavorable exploratory results -- projects net imports to reach 16.4 million barrels per day by 1980. For details, see Appendix A.

26. It is also unlikely that high levels of demand will coincide with low levels of domestic supply. In these circumstances, the economic interaction of demand and supply would work toward higher prices and this in turn would tend to narrow the import gap from both the demand and supply side. A sharply widening gap between demand and availability of domestic supplies is also likely to push public policy towards various measures aimed at mitigating reliance upon imports. Thus, the chances are that imports will fall somewhere in between the low and high of the ranges set out above.

27. On balance, then, it looks like the level of U.S. oil imports by 1980 will be upwards of 7 1/2 million barrels daily. With this substantially increased level of imports, the United States will inevitably have increasing concern over the origin of its imported oil supplies. From the standpoint of security, imports from Canada would thus be a preferred source of supply, even more so than heretofore (of which more in Section III).

28. Beyond 1980, the picture becomes much less certain. Policies adopted during the 1970's could have a very considerable impact by that time. Certainly by 1985 or so, intensified efforts to find conventional crude oil resources could provide large volumes of new production. The biggest question mark is how much may be found in frontier areas.

29. Exploration in Alaska is now stalled, largely by pipeline delays and questions of land selection by the State and native groups. Alaska contains vast sedimentary basins both onshore and offshore which have been scarcely touched by exploratory activity. Once pipeline timing becomes clear and new areas are opened up for leasing, there is the possibility that substantial additional reserves beyond Prudhoe Bay will be proved up in Alaska. Another potential but up to now unexplored North American producing area is offshore the U.S. East Coast. This area has not yet been made available for leasing -- and environmentalists have mounted a campaign to prohibit or at least delay exploration in this area. But in view of the Nation's need for oil -- and especially secure oil -- this area probably will be opened up eventually. Deeper producing horizons in established areas and prospects in deeper waters off the Gulf Coast may also yield substantial volumes of oil.

30. Over the long run, U.S. synthetic oil from shale and coal could also play an important role in U.S. oil availability. The pace and scale of development will depend both upon the nature and timing of governmental policies and the uncertainties of technology and economics in synthetics manufacture.

31. Thus, the trend in U.S. oil imports beyond 1980 is less certain than the trend between now and the end of the decade of the 1970's. If the U.S. domestic exploration efforts turn out to be very successful and/or very serious energy conservation measures are implemented, U.S. import requirements in the period 1985-1990 might actually turn out to be lower than in 1980.

32. What happens in the interim -- i.e., after the short run period in which large increases in imports look almost inevitable and before the long run in which there are major areas of uncertainty -- will depend largely on the timing of events. The rapid development of major new domestic supplies -- e.g., the early discovery of several new "Prudhoe Bays" or the opening up of a major new producing province offshore -- could cut back the growth in imports by the early 1980's. On the other hand, if expanded U.S. exploration is not successful early on, the period of rapidly rising oil imports could continue on into the mid 1980's.

33. What stands out in this brief review of future U.S. oil balances are several basic conclusions --

> In the short run (i.e., through 1980), the body of opinion within industry and government is that there will be a substantial shortfall between U.S. oil demand and supply, with oil imports increasing sharply and meeting a much larger share of U.S. oil requirements.
>
> Over the longer run, there is much greater uncertainty as to how large U.S. oil import requirements will be, with the outcome depending primarily on U.S. energy/import policies and the success of domestic exploration efforts.

> In the interim, there are questions as to timing of potential new major sources of domestic supply and their impact on U.S. oil import requirements at any particular point in time.

34. This outlook for U.S. oil balances is generally quite favorable for Alberta tar sands development. Inevitably rising import volumes through the 1970's will give heightened concern to security of U.S. oil supplies over the longer run. In this environment, the United States is likely to look to all potential sources of new large-scale North American oil -- including tar sands. Furthermore, from the standpoint of meeting U.S. requirements, tar sands would appear to hold out the potential at least of development of larger volumes of production at an earlier date and with somewhat less uncertainty than U.S. synthetic supplies from oil shale and coal. All this, of course, is without reference to other factors bearing on tar sands development, which we consider in the sections following.

II. COMPETITIVE CRUDE OIL VALUES

1. As discussed in the preceding section, sharply rising U.S. oil import volumes will provide potential market outlets for tar sands oil. The economic incentives to development of tar sands to supply this potential market -- as well as the opportunities for the Province of Alberta to benefit from its tar sands resources -- will depend upon the market value that will attach to tar sands oil and costs of production and transportation. In this section, we review the major factors bearing on competitive crude oil values in the North American market over the years ahead. In Section III, where we consider the possible directions in public policy, we also review how future U.S. policies may bear upon the relative prices of gas, oil, and various petroleum fractions and their implications for the value of synthetic oil from the tar sands.

2. Looking some years ahead, the basis on which Canadian oil is priced will depend importantly on the development of Canadian oil balances. If production continues to be largely from the provinces of Western Canada and rates of finding of new reserves do not improve very significantly, Canada's export potential could disappear by the 1980's, perhaps even earlier. In the event, Canadian crude would move primarily into domestic markets and pricing could tend to reflect Western Canadian "resource costs" -- i.e., a price that would cover all costs of making oil available, including a return on investment that is adequate to compensate for the risks involved -- and the delivered cost of foreign oil in perimeter markets.

3. However, the chances are that the provinces of Western Canada will not be the only sources of Canadian production and that Canada will maintain a substantial export potential. Major exploration efforts are now underway in frontier areas. In view of the high costs of development and transportation of frontier oil, large reserves and high well productivities are required for commercial operations. Thus, if Mackenzie Delta or Arctic Islands oil is produced, the levels of production would be on a relatively large scale and Canada would probably continue to maintain a substantial level of exports. Large-scale development of tar sands oil would also serve to maintain a continued Canadian export potential. If a substantial export flow to the United States is maintained, the value of Canadian oil exports will be largely determined by economic circumstances and governmental energy policies in the United States. And unless Canada should move to a dual pricing system, all Canadian oil prices would tend to reflect crude values in U.S. markets.

4. Looking backward, the progressive expansion of Western Canadian oil into more distant markets tended to depress Canadian wellhead prices, with lower prices required to compete with other crude streams. But looking forward at North American oil balances, as set out in Section I, and the future directions of public policy, as will be discussed in Section III, the movement of Canadian oil into U.S. markets will work to press Canadian prices upward over the years ahead. Thus, for Alberta, the development of large-scale tar sands production would not only add to the Province's output but could also serve to enhance the value of production through maintenance of Canada's export potential and the resulting favorable impact on Canadian oil prices.

5. The price of Canadian oil in U.S. markets will reflect several factors. First, anticipated pressures on both foreign and U.S. crude oil prices will bear also on Canadian oil. From its standpoint, Canada will obviously want Canadian oil exported to the United States to be valued in line with U.S. crudes and would probably expect such prices for Canadian oil in view of its security value to the United States. From the U.S. standpoint, higher prices for Canadian oil are compatible with its interest in providing incentives for exploration and development of North American resources. (By way of contrast, higher prices for offshore oil tend to be largely siphoned off by governments, with little direct contribution to exploration incentives.) Canadian oil will be able to command at least as high a price in U.S. markets as foreign oil and probably even a significant premium, if U.S. crude oil prices are above the delivered price of foreign oil.

6. It is most likely that the long-run costs of finding and developing U.S. oil resources will determine North American crude oil values, with Canadian oil being able to command prices in line with these costs. However, it is at least possible that the costs of Canadian oil resources might be price determining at some point in the future. This could happen over the decade of the 1980's -- if Canadian Arctic and tar sands oil were contributing larger incremental volumes than new discoveries in the U.S. and the costs of these incremental Canadian supplies were higher than the cost of incremental U.S. supplies. In the event, North American price levels would have to rise high enough to support production and transportation of incremental Canadian supplies in order to ensure their contribution to the security of U.S. oil supplies. The cost of Canadian oil would probably have to be substantially higher than the cost of foreign oil before the United States would opt for more foreign oil instead, leaving Canadian resources undeveloped. The United States could be willing to pay a considerable premium for Canadian oil -- if required to support the economics of development, production, and transportation.

7. This is also true for Canadian natural gas. The United States is now moving to a system of multiple prices for gas from various sources. Although long-run gas pricing policies are still somewhat uncertain, it is reasonably clear that the United States will be willing to pay a price for North Slope and Canadian Arctic gas that at least covers resource cost (including profit) plus transportation. The costs associated with making these streams of gas available will thus be a price-determining factor. The United States would not insist upon a netback price that would inhibit the development of these gas resources, which could make an important contribution to the security of U.S. gas supplies.

8. We begin this section with a look at foreign oil balances and foreign concessionary developments. These factors will affect the terms and conditions under which foreign oil will be available to meet North American oil import requirements. The interplay of foreign and domestic availability and costs will bear upon both the economic circumstances of North American oil and the formulation of U.S. and Canadian oil policies. In the final part of Section II, we consider likely trends first in U.S. and then Canadian crude oil prices.

Requirements versus Availability

9. Oil demand outside North America (and excluding Soviet Bloc countries) is projected to rise from around 25 million barrels daily in 1972 to some 45 million barrels per day by 1980. This would represent growth of around 7 3/4 per cent per annum, or somewhat slower than the 10 1/2 per cent rate experienced over the decade of the 1960's. The slowdown reflects the somewhat slower rates of economic growth anticipated in industrialized areas such as Western Europe and Japan and the competitive impact of natural gas in Europe and nuclear power in Europe and Japan. Even with slower rates of growth, however, the absolute increases in foreign oil consumption are very large.

10. Foreign oil production will also have to meet North American import requirements. As noted in the preceding section, the U.S. import requirements could be in the range of 7 1/2 to 13 million barrels daily by 1980. Eastern Canadian imports by 1980 are projected to be somewhat over 1.0 million barrels per day (assuming that Eastern Canadian oil requirements continue to be met by foreign oil).

11. The bulk of increased production will have to come from the Eastern Hemisphere. In 1972, 26 million barrels daily, or about 85 per cent of foreign production came from the Eastern Hemisphere. Of this total, 18 million barrels per day, or 70 per cent, came from the Middle East. Substantial new production is likely to be established in such areas as the North Sea, West Africa, Southeast Asia, and Indonesia. But to meet expanding demand, Middle East production will have to about double by 1980. The required increase in Middle East production of 15-20 million barrels daily would be more than the increase in production from all other foreign areas combined.

12. Eastern Hemisphere reserves, reported at around 500 billion barrels, now constitute some 54 years' supply at current rates of production. A reserve life index of 25 years in 1980 at production levels then would require interim discoveries of about 20 billion barrels; a 33 years' life index,

discoveries of around 150 billion barrels. By way of comparison, gross additions to reported Middle East reserves came to 130 billion barrels over the last 5 years. As an example of the productive potential of the Middle East, Aramco spokesmen have said that Saudi Arabian production of 10 million barrels per day (versus 5.7 million in 1972) could be achieved in the near term and a further substantial expansion to 20 million barrels daily is possible by around 1980.

13. From the physical standpoint, the outlook is thus for a continuing sufficient balance between foreign oil requirements and productive potential over the decade. The necessary expansion of production will be supported by Middle East resources. Incoming sources of supply from other areas will contribute to the competitive flow in world oil trade.

14. The Middle East will play a pivotal role in world oil. It will be the major source of supply and the source of the incremental volumes needed to meet world oil requirements. The costs of Middle East oil will be the basis of competitive price/cost relationships in world oil markets. And the Middle East will serve as the political fulcrum for changing concessionary arrangements in producing/exporting countries.

15. Four factors enter into the competitive pricing of oil in world trade -- physical production costs, production payments to host governments, transportation costs, and profit margins. Physical production costs are generally lowest in the Middle East -- in the range of 10-20 cents per barrel -- and will remain so for incremental production. Physical costs may increase somewhat over the years ahead, but they represent a small proportion of f.o.b. foreign oil costs and an even smaller proportion of delivered costs in North America. Government "take" accounts for the largest part of foreign oil prices and is clearly pointed upward. Tanker transportation costs from the major exporting areas to North America, if anything, are apt to go lower, as escalating construction and operating costs are more than offset by the economies of larger-scale tankers (assuming that adequate port facilities become available). If the oil companies are still operating as concession holders or some other type of preferred offtakers by the end of the decade, they will strive to maintain their margin of profit on crude production. However, host governments will increasingly try to shift this margin away from the companies and to themselves.

Concessionary Developments

16. As indicated, the upward pressure on foreign oil prices will come primarily from escalating "take" by producing governments. Tripoli (two times around), Teheran, and Caracas witnessed a dramatic sequence of confrontations and enforced settlements between concession-holding companies and producing countries in 1970-71.* Unprecedented cost increases were imposed by higher posted (tax reference) prices and higher tax rates. And again in 1972, the Geneva and subsequent currency agreements imposed still higher costs on the companies. In course --

> The tax-paid cost (i.e., physical producing costs plus royalty/income taxes) of a light Persian Gulf crude was boosted from $1.02 (third quarter 1970) to $1.62 at present;
>
> Libyan crude, from $1.41 to $2.52;
>
> Venezuelan medium crude, from $1.51 to $2.24.

Built-in posted price escalation to 1975 will boost Persian Gulf costs by about another 15 cents.

Participation

17. Beyond this, the oil industry has recently agreed to participation by governments in their established concessions in the major Arab producing countries in the Persian Gulf. The governments' initial share, beginning in 1973, will be 25 per cent, rising to 51 per cent by 1982. Implementation of participation will mean both additional "costs" to the industry beyond already agreed taxes/royalties and in time ultimate control by governments over producing operations.

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* Appendix F -- Foreign Concessionary Developments -- reviews recent concessionary developments in major producing countries. The Appendix focuses particularly on the economic and political implications of concessionary developments for current and future oil costs and the shifting balance of power between concessionary companies and host governments.

18. Under participation, the governments' shares of production will be put back upon the companies, at least to a considerable extent and for some time to come. In these circumstances, the difference between the agreed "buy-back" prices and tax-paid cost (i.e., the cost of equity crude to the companies) will raise the companies' average cost per barrel lifted. This difference represents in effect a guaranteed margin of profit to the governments on their share of production "sold" for them by the oil companies. On the basis of buy-back prices agreed for light Persian Gulf crude for 1973-1975, the average cost of crude lifted by the companies will increase by about 10 cents per barrel.

19. Over this period of rapid changes in concessionary terms and sharp increases in government take, foreign crude oil balances were tightened by a number of developments, including production cutbacks and nationalization of the BP interests in Libya, nationalization of the major Iraqi concession, and a government-imposed ceiling on production in Kuwait. In an economic environment of tight supplies, the companies were able to recover all of the higher costs imposed on them by producing governments and beyond that even to increase their profit margins somewhat. By way of illustration, the going market price for a light Arabian crude oil increased from approximately $1.30 per barrel in mid-1970 to a price now being quoted for 1973 deliveries of around $2.15 per barrel, or an increase of some 85 cents.

A Forward Look

20. Both the costs and the conditions under which Middle East crude will be produced are very uncertain for the future. Indicative of this uncertainty, where a few years ago long-term contract prices for foreign crude oil were below short-term or spot prices, now it is very difficult to write a long-term contract for foreign crude oil at any price.

21. Both the Teheran agreement on taxes/royalties and agreed buy-back prices under participation are due to expire at the end of 1975. However, there is no real assurance that even these terms will hold firm until that time.

If the companies are successful in passing along participation "costs," as now seems likely, the producing governments will be earning a profit margin on their participation oil lifted by the companies that is less than the profit the companies make on their own equity shares in production. Thus, the governments will almost certainly look to boost buy-back prices, taking for themselves the full margin of profit earned by the companies. The rising trend in world oil prices through 1975 will also lead governments to push again for higher tax-reference prices and/or tax rates in 1976, if not sooner.

22. OPEC countries do not see any effective ceiling on their financial demands from either competing sources of oil or alternative energy supplies. Despite incoming production from such non-OPEC areas as the North Sea, OPEC oil will continue to supply the bulk of crude moving in world oil trade and will be required in large volumes to meet total world oil requirements. Nuclear power will be increasingly competitive with electricity generation and, in Western Europe, natural gas will provide competition for oil in certain end-uses. But for most end-uses and in most areas, there does not look to be any real competitive alternative to OPEC oil.

23. In view of the uncertainties surrounding costs/prices and the political/institutional circumstances under which oil will be produced, it is obviously very difficult to quantify future trends. However, taking a simplistic approach, one can set out what would look to be a lower limit on future escalation in foreign oil prices. First, the recent devaluation of the U.S. dollar will result in an increase in taxes/royalties on Persian Gulf crude of approximately 10-15 cents per barrel under the Geneva currency agreement. Then, there are the further increases in taxes/royalties of around 15 cents per barrel through 1975 already built into the Teheran agreement noted earlier. If the reopening of the Teheran agreement in 1976 did no more than follow the pattern of the past, this would add another 50 cents or so to government take through 1980, assuming no further upward adjustments for currency changes. The producing governments will also look to get the full profit from their participation oil that the companies get on their own equity oil after passing along the "costs" of participation. Putting all of these together, the result would be an increase between 1973 and 1980 of at least another $1.00 per barrel in the lifting cost of Middle East oil. However, this represents only a minimum increase based on a projection of past trends and the assumption that present institutional arrangements will continue.

24. Increases in foreign oil prices could be substantially larger than the minimum set out above, but quantification becomes even more uncertain. Participation itself is a very new institutional arrangement, substantially modifying the concession system but falling short of full nationalization. Whether participation will last for any length of time in its present form and under agreed terms is subject to some doubt. Iran is not covered by participation and the companies are currently negotiating with Iran on new arrangements for the future. The Shah will obviously want better terms than conceded by the companies to the Arab States of the Persian Gulf -- and will be virtually compelled to succeed from a political standpoint. If so, the "participation countries" will be back for more. At the least, the result could be another round of leapfrogging in financial benefits to producing countries, with inevitably higher oil prices. Beyond that, there could be a more dramatic breakdown in existing arrangements and further erosion and perhaps even a complete loss of the companies' concessionary interests.

25. In the event of major changes in the circumstances of production, predicting the effect on trends in foreign oil prices is especially difficult. If the producing countries operate on their own, the present "cost basis" of foreign oil pricing -- i.e., prices set at margins above the cost of oil to companies, including payments to producing governments -- would be eliminated. Absent such a cost basis, the pricing of foreign oil would be politically determined.

26. It is possible in this kind of environment that competition among producing governments might begin to reverse the upward trend in foreign oil prices. This could be the case if sufficient numbers of important producing countries with expansible production would seek maximization of output and revenues through market competition.

27. However, it looks like the increase in Middle East production that will be required to meet over one-half of the total increase in Free World oil requirements by 1980 will have to come from a relatively few countries. The required increases in production will be forthcoming primarily from the huge reserves of Saudi Arabia, expanded output in Iran, and perhaps also from the development of reserves and production in Iraq and Abu Dhabi. Under these circumstances, upward pressure on world oil prices could probably be maintained, even without a formal "world oil cartel" and agreed upon sharing of markets by producing

countries. If two or three countries have control over the reserves necessary to meet rising world oil requirements, each could probably expect very substantial growth in export volumes while reasonably adjusting increments in productive capacity so as to maintain the upward pressure on prices. Unless and until there were sufficient alternative crude oil supplies developed to make continued volumetric gains difficult for these countries -- or alternatively an effective ceiling on prices set by alternative energy supplies, which appears unlikely except in the marginal North American market -- it is difficult to contemplate other than continued upward trend in foreign oil prices.

28. Against a background of mounting oil requirements, concentration of required oil reserves in a few countries, and a lack of realistic alternatives, it seems unlikely that the increase in foreign oil prices will turn out to be the minimum set out above. The minimum would represent an increase from approximately $3 to $4 per barrel in the price of Middle East oil delivered into North America and Western Europe. This is an increase of only some one-third over seven years, or about 3 1/2 per cent per annum. OPEC has sought to protect the purchasing power of oil revenues against rising prices for other commodities and services in world markets, as also against unfavorable changes in the rate of exchange for currencies in which they are paid (largely U.S. dollars). In a world plagued by inflation, another $1 per barrel by 1980 would probably not even represent an increase in the real price of oil.

29. Thus, attempting to be somewhat more realistic, the increase in the price of Middle East oil -- which will be the price-determining factor in foreign oil markets -- could be twice or more the minimum $1 per barrel set out above. On the demand side, pressure will come from rapidly rising world oil requirements. On the supply side, the key factor will be the pivotal role played in investment, production, and pricing decisions by the governments of a few major Middle East countries -- either indirectly through their decisive voice under participation or more directly if participation gives way to full government control of producing operations.

30. Looking beyond 1980, the uncertainties are even that much greater. The rate of growth in oil demand is expected to slow down significantly in the 1980's, but the absolute increases will nonetheless still be very large. If interim discoveries of new reserves are disappointing, the ratio of reserves-to-production in the Eastern Hemisphere could be pulled down to something like 25-30 years by the early 1980's. In these circumstances, physical availability of crude oil might actually be tight. At that point also, the cost of replacing reserves could add further to the pressures on foreign oil prices.

31. What comes out of this is that whatever one sees through 1980, the cost/price basis of foreign oil will be pointed still higher after 1980. In the latter period, there is an added question mark as to the continued physical availability of oil to meet rising requirements. Uncertainty over availability in itself is likely to provide further upward pressure on prices.

32. Turning to North America, the picture is one of rapidly increasing prices for increasingly insecure foreign oil supplies. It is not only that foreign producing areas are insecure, but the rising proportion of North American oil supplies that must be drawn from these sources makes the problem that much greater. Basic policy decisions will revolve around the development of North American resources in an effort to achieve once again a reasonable degree of security of oil supplies. A key issue will be the price the United States is prepared to pay to provide incentives for development.

33. Trends in foreign oil should work to the advantage of tar sands development. Rising costs of foreign oil add to the economic attractiveness of the tar sands and uncertainties over access to foreign oil enhance the strategic advantage of direct access to tar sands oil, particularly for major integrated companies (of which more in Section IV).

North American Crude Oil Prices

34. Public policy, which is considered in more detail in Section III, will bear very importantly on future North American crude oil prices. At this point, we attempt only a brief discussion of future U. S. and Canadian crude oil prices, drawing upon the trends in North American oil balances and foreign oil developments discussed earlier.

U. S. Prices

35. In the short-run, internal pressures in U. S. crude oil markets could be an important factor working to push U. S. crude prices upward. U. S crude oil blanaces are likely to be increasingly tight over the years immediately ahead, with domestic production pressing on capacity. While aggregate volumes of permissible crude imports should be set high enough to balance total U. S. crude requirements, the pressures on domestic supplies are still likely to be very strong. Demand for domestic crude will be particularly strong from various U. S. inland refiners who cannot utilize import rights very effectively either to import crude directly or as leverage to obtain domestic supplies. This could continue to be the case for some time, until oil flows within the United States are re-oriented to much larger volumes of imports and domestic supplies move into refineries where they can be most economically utilized.

36. The costs of foreign oil delivered into U. S. markets will be a key factor in the determination of future U. S. crude oil prices. The escalating costs of foreign oil would in any case set a floor under pricing of U. S. crude oil supplies. Over the long-run, the real question is whether the volume and cost of North American energy resources will set a ceiling on what the United States has to pay for its oil supplies.

37. To the extent that sharply rising foreign oil prices move above parity with U. S. prices, they would also tend to pull U. S. prices upward. However, for many years, the United States has been willing to pay a price for domestic crude that has been significantly above the delivered price of foreign oil. For the future, whatever form oil import policy might take,

the United States would probably be willing to continue paying some premium for domestic crude oil supplies -- if required to support a viable domestic industry and provide incentives to domestic exploration and the development of synthetic production.

38. As the United States has to draw an increasingly large proportion of its supplies from insecure foreign sources, available supplies of domestic (and Canadian) crude will take on even greater importance to U.S. security. In the past, the United States might have expected to gain some margin of security in access to foreign oil through the major concessionary interests of its international oil companies. But now there is considerable uncertainty even as to the future tenure of U.S. companies over foreign oil reserves.

39. The United States also faces rapidly rising foreign exchange costs for its mounting import volumes. Both on a per-barrel basis and in total, a large proportion of the delivered price of foreign oil represents a foreign exchange drain for the United States. U.S. oil companies do repatriate profits to the United States on foreign production, but the largest and an increasing part of foreign oil costs represent payments to foreign governments. Thus, every barrel of domestic oil consumed instead of foreign oil represents an important foreign exchange savings for the United States. For a U.S. economy faced with mounting balance of payments deficits, this could be a significant factor in the price it is willing to pay for domestic oil.

40. Over the long-run, the only way the United States can minimize the problems of over-dependence on offshore oil is to encourage the development of North American resources. The United States must provide the incentives for exploration and development of conventional North American crude oil and for production of marginal fields. The United States will have an equally strong interest in development of synthetic oil production from its vast reserves of shale and coal, as also from Alberta tar sands. Over the long run, these synthetic supplies could make a major contribution to the security of U.S. oil supplies. Furthermore, at some time in the future, the cost of making these supplies available could serve as a potential ceiling on the price the United States has to pay for oil.

41. It will inevitably be many years before North American oil resources may be capable of making the continent once again reasonably self-sufficient and providing a potential ceiling on the price that must be paid for oil supplies. Just when this might take place and at what level of resource cost cannot really be predicted in advance. In the interim, however, rising U. S. crude oil prices will be essential to reaching these goals -- providing incentives for conventional exploration/development and a target for the development of synthetics.

42. As with foreign oil prices, all this is almost impossible to quantify with any degree of accuracy. However, as a working hypothesis, what we may be looking at is a trend in U. S. prices pointing in the direction of $5 per barrel crude oil for the period under consideration. This trend could be tempered somewhat by early, large-scale development of domestic resources at favorable costs -- but this is not likely before the 1980's at least. On the other hand, the trend could be accelerated, reaching this target sooner than 1980 and perhaps going above it, if domestic finding results are disappointing and foreign oil prices escalate very rapidly.

Canadian Crude Prices

43. In 1959, Canadian crude prices were adjusted to bring them in line with U. S. crudes in new perimeter markets to which they were moving, including the U. S. Midwest. In the latter half of the 1960's, Canadian crude prices failed to increase in line with several hikes in U. S. crude prices. As a result, Canadian crude developed a considerable margin of competitive advantage over U. S. crudes in northern U. S. refining centers over this period. However, increases in Canadian prices in November 1972 and again in January 1973 have brought the delivered price of Canadian crude back within 10-15 cents per barrel of the delivered cost of U. S. crudes in major U. S. Midwest refining centers.*

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* For details, see Appendix C -- Canadian and U. S. Crude Oil Prices. Appendix Table C-1 sets out a chronology of the wellhead price of a representative Alberta crude and the reasons for price changes. Appendix Tables C-2 through C-5 show the current competitive position of Alberta crude in four U. S. refining centers -- Chicago, Toledo, St. Paul, and Puget Sound.

44. For the future, one would expect reasonable alignment of Canadian crude prices with U. S. prices on shipments to U. S. markets. While such price alignment could add to the cost of U. S. oil imports, it is not contrary to other basic U. S. interests.

45. In the past, large price differentials between Canadian and U. S. crudes in competitive markets have compounded the difficulties of controlling the volume of permissible imports from Canada, so as to accord with other imperatives of U. S. import policy, and of allocating the permissible volume of Canadian imports among U. S. refiners. The closer Canadian oil is to equalization with domestic crudes, the more competitive factors bear on volumes of Canadian crude taken by U. S. refiners and on the distribution of imported Canadian crude into U. S. refining centers where its comparative advantage would be greatest. That is to say, when Canadian crude prices reasonably reflect crude values in U. S. refining centers, the margin of penetration is more susceptible to commercial choice and less dependent upon controls and allocations.

46. More important for the long run, Canadian export prices provide incentives for exploration and development of Canadian oil resources. It is clearly in the U. S. interest to encourage the development of all North American resources.

47. As noted at the outset, it is not out of the question that Canadian crude could be price-determining in North American markets over the longer run, depending upon the relative rate of development of new productive capacity and relative costs in the two countries, In these circumstances, it would be U. S. crude prices that would align with the delivered price of Canadian crude in U. S. refining centers to which both crude streams were moving. Prices related to Canadian costs would be required in U. S. markets to support the development and importation of Canadian crude.

48. However, even if the costs of finding and developing U. S. oil resources set basic price levels in U. S. markets, it would still be in the U. S. interest to see Canadian exports realize essentially the same prices as U. S. crudes in U. S. markets. In these circumstances, returns on development of Canadian resources for export could be more favorable than returns on development of U. S. resources. But these favorable returns would have the effect of stimulating exploration for Canadian crude and development of the tar sands for export to the United States, to the extent Canadian policy permits such exports.

A Two-Price System?

49. Canada would have an obvious interest in seeing its oil exports realize prices in U. S. markets in line with U. S. crude prices. However, price parity with U. S. crude on export sales does not necessarily mean that the same price has to apply on sales to the Canadian markets as well. There may be objections within Canada to paying higher prices for Canadian oil which reflect primarily intensified demand in U. S. markets rather than the pressure of Canadian resource costs.

50. With U. S. oil prices pointed sharply higher, Canada might consider some type of two-price system. On export sales, prices would be what could be realized in U. S. markets. On domestic sales, prices would be related to the cost-basis of Canadian oil -- and presumably lower, at least for some time to come. If export prices were higher than domestic prices, there would also have to be controls over export volumes and presumably some method of allocating sales among producers.

51. From an economic standpoint, there are always questions as to the desirability of a two-price system. A single price has the effect of allocating available supplies to markets where value is highest. Under a dual price system, relatively low oil prices in Canadian markets would tend to stimulate Canadian demand for oil, pushing Canadian oil into more distant markets and into a wider range of competitive end-uses. Whether this is desirable would depend in part on how Canada views the importance of low-cost energy for Canadian consumers and domestic industry.

52. For Canadian producers, a dual-price system would mean less-than-optimum realizations and returns on investment. The effect would be somewhat lower incentives for development of both conventional Canadian crude oil and tar sands than if Canadian prices were allowed to rise to parity with export realizations.

53. Canadian domestic oil prices are, of course, a matter for Canada to decide. We would not presume to pass on what Canadian policy should be or even to attempt to predict what it will be.

54. In sum, future price trends look favorable for tar sands development. The price of foreign oil delivered into North American markets is headed sharply upward. Escalating costs of foreign oil will provide a floor under pricing of U. S. crudes. Beyond that, U. S. crudes may continue to earn some premium over the delivered price of foreign oil, if required to support a viable domestic industry and provide incentives to domestic exploration and the development of U. S. synthetics. Prices for Canadian oil -- at least on exports to the United States -- can generally be expected to follow the trend in U. S. crude oil prices.

III. DIRECTIONS IN PUBLIC POLICY

1. In this third Section, we turn to a look at basic directions in public policy in the United States and Canada which may bear upon the development and marketing of Alberta tar sands oil. The focus here is primarily on the broad interaction between U.S. and Canadian policies as these may affect demand for Canadian oil and Canadian oil prices. In Section IV, we consider in more detail specific implications of policy trends for future tar sands development.

2. We begin with a look ahead at U.S. policies with respect to energy utilization, development of indigenous resources, and energy imports. Then we consider policy issues on the Canadian side, with the emphasis on disposition of prospective Canadian production and import/export policies.

U.S. Policy Issues

Levels and Origins of Oil Imports

3. The analysis of Section I pointed very clearly towards a widening gap between domestic oil demand and availability in the United States over the balance of this decade. With mounting dependence on foreign oil, the origin of U.S. oil imports will become increasingly important.

4. U.S. concern over security of imported oil supplies has obviously been heightened by recent developments in foreign oil.* As noted, we have seen unprecedented demands upon the international oil industry by the major oil producing countries, dramatic confrontations with threats to withhold essential oil supplies, and far-reaching "settlements" which have increased the cost of foreign

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* For details, see Appendix E -- Foreign Concessionary Developments.

oil supplies very substantially. Then came "participation," which will not only add further to foreign oil costs, but will reduce and eventually eliminate control by the oil companies over foreign reserves and production. Furthermore, within the last year, Libya nationalized the producing properties of BP; Iraq nationalized the Iraq Petroleum Company, which accounts for the largest part of Iraqi production. Added to this are the uncertainties that Iran now poses.

5. In view of the uncertainties surrounding the security of supplies from virtually all major Eastern Hemisphere producing areas, the United States is likely to try to limit the proportion of its imports from those sources. However, in the short run (i.e., at least over the next five years or so), a relatively large share of increased imports will almost inevitably have to come from the Eastern Hemisphere. The United States will welcome stepped-up imports from Western Hemisphere sources, especially from Canada (of which more below), but the potential additional availability from these sources looks to fall very far short of the total increase in U.S. import requirements. Thus, for the United States, there is no real alternative to increased reliance on Eastern Hemisphere oil in the near term.

6. As dependence on Eastern Hemisphere oil mounts and security concerns become even more pressing, the United States will look to policies which could serve to mitigate potential supply problems. In the short run, one of the few measures available is the stockpiling of oil inventories. This approach has recently been pressed with renewed urgency. A Defense Department spokesman, for example, recommended "mandatory establishment of reserve crude oil and products inventories by oil importers at levels sufficient to weather partial or short-range supply interruptions, or to soften the impact of larger-scale denials." This course of action was seen as the only one "which might significantly reduce the danger of some future interruption in oil supplies . . . before the larger energy programs can begin to restore the nation to a reasonable degree of self-sufficiency."*

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* From a statement by Barry J. Shillito, Assistant Defense Secretary for Installations and Logistics before Senate Interior Committee hearings on security implications of increased dependence on foreign oil.

7. For the longer run, the United States has the opportunity to bolster the security of its oil supplies -- and more broadly, its energy supplies -- through policies designed to affect overall domestic supply/demand balances and the availability of import streams from secure sources. Policies directed at providing incentives for development of North American resources -- conventional oil and gas, synthetics, and nuclear power -- would be a major part of this long-run effort.

8. Since the mid 1950's, the United States has controlled the volumes of lower-cost foreign oil that could enter U.S. markets in order to ensure the viability of its domestic producing industry. Where the delivered price of foreign oil is below domestic costs, the United States will probably continue to maintain quantitative controls on imports. In the short run, oil import volumes will have to be set at levels necessary to supplement current domestic availability. Over the longer run, oil import volumes would be progressively adjusted according to trends in domestic availability, considering reasonable rates of production from domestic reserves and taking account of such standby capacity as is deemed desirable from a security standpoint.

9. On this basis, the long-run trend in U.S. crude oil prices could be expected to reflect emerging costs of finding, developing, and transportation, including return for risks of investment. The contribution of import policy to exploration incentives would thus be assurance of domestic markets and prospects for remunerative prices. And this should carry over to Canadian oil as well (of which more below).

Interaction of Oil and Gas

10. The concerns of U.S. policy go well beyond the question of security of oil supplies to encompass a broader range of energy issues. To a much greater extent than in the past, policy-making is going to have to deal with overall energy balances and the mix of energy imports. The interaction of oil and gas supplies and prices under U.S. policy could have significant implications for Canadian exports generally and tar sands in particular.

11. The U.S. gas picture for the years ahead can be summarized very briefly as follows --

> A very large and widening "gap" between potential requirements and projected production from established producing areas, which could reach close to 40 billion cubic feet daily or about two fifths of consumption by 1980, if present trends were to continue;
>
> Higher gas prices in the United States which will work to close the potential gap by tempering the build-up in demand for gas and providing incentives for stepped-up gas exploration in the United States and for reaching out for supplemental supplies;
>
> Alternative sources of gas include LNG imports from offshore sources, SNG from liquid hydrocarbons and coal, and Alaskan North Slope gas; all of which now look to involve costs that are three and four times the current delivered cost of domestic pipeline gas in major U.S. consuming centers;
>
> Alternatively too, other energy sources that can be used in place of gas, notably oil for gas in under-the-boiler uses.

Future U.S. gas balances will depend not only on the level of gas prices, but also to a large extent on the relative prices of gas and oil (and for the long run, probably coal as well).

12. All these pose far-reaching questions of energy and import policy for the United States. Faced with a gas gap that is already at hand and expected to increase sharply, there will be strong pressures for the United States to do something as quickly as possible to bolster gas availability. There are applications pending for importation of offshore LNG and selected liquid feedstocks for SNG facilities. An obvious step would be to authorize at least some of these currently planned projects. While these sources of gas may not be the answer to long-run U.S. gas needs, they may be seen as bridging the gap until more economic and secure supplies become available.

13. If imports of LNG and SNG feedstocks are allowed, the question is why not also allow importation of crude oil for processing into residual fuel oil (or for direct burning) to serve the same end uses. Some 12 billion cubic feet daily of natural gas is currently burned as boiler fuel by industry and electric utilities on the U.S. Gulf Coast; another 5 billion cubic feet per day on the East Coast. This represents one-third of total U.S. gas consumption. As a practical matter, there is a very real question whether the United States should continue to consume these volumes of gas in "inferior" uses, particularly in areas where oil might be made available on competitive terms. The substitution of oil for gas under boilers could free gas for other "premium" uses in residential and commercial markets. Furthermore, gas freed from industrial uses on the Gulf Coast would be available for movement up the pipelines into the Midwest and East Coast. This would be particularly important in view of the increasing inability of these pipelines to contract for the gas supplies necessary to keep their pipelines full.

14. U.S. import policy could be changed to allow quota-free importation of foreign crude to produce residual fuel oil (i.e., a right to draw upon equivalent foreign crude for residual processed in the United States). The right to draw upon foreign crude for processing into residual could provide considerable incentive for U.S. refiners to increase their residual output. The price of this residual would reflect the delivered cost of foreign crude, even though in practice the residual were actually processed from largely low-sulphur U.S. crudes.

15. Residual fuel oil based on delivered foreign crude costs or even the direct burning of low sulphur crude oil could be competitive with gas in various U.S. markets over the years ahead. By way of example --

> At a gas price of 60 cents per MCF, which is already being paid in the intrastate market on the Gulf Coast, residual would be competitive on a BTU equivalent basis at $3.65 per barrel and crude oil for burning at $3.25 per barrel;
>
> At $1.00 per MCF, which is the bottom of the range of projected LNG/SNG prices, residual at $6.10 per barrel and crude oil at $5.45; and

> At $1.50 per MCF, which may be more realistic for LNG/SNG by the latter 1970's, residual at $9.15 per barrel and crude at $8.20.

On a BTU-equivalent basis, 1.0 billion cubic feet daily of gas, which might otherwise be supplied by a large-scale LNG import project or a number of SNG plants operating on imported feedstocks, could be replaced by only some 165,000 barrels per day of residual fuel oil or 185,000 barrels daily of crude oil.

16. While future oil/gas price relationships are difficult to predict, the indications are that oil could be competitive with gas in under-the-boiler uses in various U.S. markets. It would appear unlikely that future escalation in foreign crude oil versus LNG and SNG feedstock prices would work to tip the balance strongly in favor of gas and could well work in favor of foreign crude oil. To the extent that foreign oil prices move toward the upward end of the range discussed in Section II, the same political forces would directly affect the prices of foreign feedstocks for gasmaking and indirectly bear also on the price of foreign LNG.

17. Even if this economic outlook is essentially correct and relative prices favor oil versus gas, it is obviously difficult to predict what future U.S. energy policy will be and even more difficult to predict the timing of policy changes. We can only point up what look to be some of the economic realities. And these would seem to point to several basic conclusions.

18. The United States has built up very large potential demand for gas by pricing gas low as compared with other energy fuels in the past. But this does not necessarily mean that future policy has to be framed in such a way as to ensure that all this potential demand is met at whatever the cost. There are substantial opportunities for substitution of oil for gas in under-the-boiler uses. To the extent energy must be imported, crude oil would potentially offer a lower cost and a no less secure alternative than LNG or SNG.

19. All this means that the prices now being widely bruited as necessary to elicit gas supplies for the U.S. market may not necessarily be the prices that bring potential U.S. gas requirements and supplies into

balance over the long run. If U.S. energy and import policy is framed in such a way as to allow oil to meet energy needs that would otherwise be met by gas, the demand for and price pressures on gas may be less than currently being projected. The corollary is that the demand for and price pressures on oil may be greater than now anticipated.

Implications for Canadian Exports and the Value of Tar Sands Oil

20. This outlook could have important implications for Canadian exports of both oil and natural gas. First, it casts doubt at least on the assumption that Canadian gas exports will automatically be able to realize prices in U.S. markets in line with the high costs of LNG and SNG. Early LNG and SNG projects will become part of base-load supplies and their costs subsumed within the U.S. gas economy. However, unless there is a continuous process of new additions to LNG/SNG capacity, the costs of these supplies will be largely irrelevant for pricing of later incremental gas volumes.

21. A more rational use of gas in the United States through substitution of oil could mean both lower levels of gas consumption and somewhat lower gas prices than if all potential gas demand is met regardless of cost. In these circumstances, Canadian gas would tend to be utilized primarily in "higher" end uses and supply a larger share of a smaller U.S. gas market. And the pricing of incremental supplies of Canadian gas exports might be more closely related to the costs of making the gas available -- including profits (and taxes/royalties!) -- than to the alternative cost of expensive LNG/SNG.

22. In contrast, U.S. policies designed to encourage the substitution of oil for gas would tend to work to the advantage of Canadian oil. Larger volumes of oil consumption -- and hence larger oil imports -- to meet energy demands that would otherwise be met by gas would add to the importance of oil supplies from secure sources. To the extent that increased oil demand pushes U.S. oil prices higher, this would also be favorable for realizations on Canadian oil exports. If oil plays a larger role in meeting U.S. energy needs, Canadian oil could make an important contribution not only as a refinery feedstock, but also as a significant source of clean (i.e., low-sulphur) fuel in competitive energy markets.

23. A shift from gas to oil in U.S. energy markets could have special implications for the value of tar sands oil vis-a-vis other crude oils. Synthetic crude oil produced from the tar sands is relatively low in sulphur.* Thus, various fractions from tar sands oil -- or even the whole synthetic crude -- should be acceptable and desirable products for burning.

24. As far as overall composition is concerned, synthetic crude from tar sands contains no fraction that can be classified as residual. As compared with conventional crude oil, an unusually large fraction of synthetic tar sands crude is in the distillate range. For the main output of the GCOS plant, for example, some 50-55 per cent reportedly is a gas oil range product (500-950°F) and another 20 per cent or so is in the kerosene range (395-530°F). In addition, another product -- so-called "Product B" -- is also produced and moved separately. This product is also in the light distillate (370-550°) boiling range.

25. In general, the outlook for demand for distillate products and for distillate prices in the United States is quite favorable. A shift away from gas to oil for burning purposes would stimulate demand for distillates -- either directly or for blending with residual fuel oils to reduce their sulphur content. Over the years ahead, the average barrel of product demanded in the United States could move away somewhat from the very heavy preponderance of gasoline and towards the distillate and residual fractions.

26. Furthermore, the competitive energy sources that had tended to hold down prices for distillates and residual in the past -- natural gas and coal -- are in the future going to be much higher in cost or not acceptable

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* However, it should be noted that synthetic crude from the GCOS plant is apparently not as low in sulphur as originally projected -- i.e., 0.2 per cent by weight, rather than an anticipated 0.03 per cent. Furthermore, some projections of sulphur content from the Syncrude facility cover a range up to 2 per cent sulphur.

from an environmental standpoint (notably high-sulphur coal). Thus, distillate and residual prices could rise relatively sharply and these fractions could become increasingly valuable to U.S. refiners. The cost of producing environmentally acceptable gasoline looks to be pointed much higher and these higher costs will probably be reflected in gasoline prices. However, the impact of these trends in the profitability of gasoline manufacturing and thus the relative value of the naphtha fraction is uncertain. In the event, a crude oil with a high distillate content such as a synthetic crude from the tar sands could command a relatively high value vis-à-vis crude oils generally.*

Canadian Oil Under U.S. Oil Import Policy

27. The various policy developments above are clearly quite favorable for the outlook for Canadian oil exports to the United States. From the standpoint of security of U.S. oil supplies, imports from Canada will be a preferred source of supply. U.S. policy is certain to recognize a substantially larger volume of Canadian oil as an essential supplement to domestic production.

Short-Term

28. In the past, the United States has felt it necessary to control the volume and rate of build-up of oil imports from Canada -- first informally and more recently through formal quotas for East-of-the-Rockies crude oil imports.** U.S. policy was concerned with the possible displacement

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* It should also be noted that the gas oil fraction of the GCOS crude is reportedly a good catalytic-cracking feedstock. Thus, tar sands crude could be a valuable crude even if there were relatively little shift from burning gas to oil and the U.S. oil economy remains heavily oriented to gasoline.

** For details, see Appendix B -- Canadian Oil Under U.S. Oil Import Policy. Appendix Table B-1 sets out a chronology of U.S. oil import policy with regard to Canadian oil from 1955 to date. The Appendix also deals with the relative role of Canadian versus offshore oil in meeting increased U.S. import requirements over the years and the role of exports in the build-up of Canadian oil production since 1956.

of domestic production by Canadian oil and also the potential impact of Canadian imports on access of other Western Hemisphere (notably Venezuelan) oil to U.S. markets. However, with domestic production at or near capacity and total U.S. oil imports inevitably rising sharply, concern with the impact of Canadian oil on domestic and other foreign supplies has largely disappeared.

29. In the United States, the argument has also been made that Canada is able to import lower-cost foreign oil in the East while supplying the United States with higher-cost Canadian oil in the West. Canada thus gets the benefit of cheaper foreign oil, but does not pay its share of the burden of high-cost North American oil that provides a margin of security for all of North America. On this basis, it has been argued that Canadian imports should not be opened up until Canada moves to "harmonize" its oil import policies with those of the United States. However, with both U.S. oil imports and foreign oil costs rising sharply, this issue is also likely to diminish in importance.

30. At the time of writing, Canadian crude oil imports into Districts I-IV (East-of-the-Rockies) are still subject to quotas. Indications are that formal quota restrictions on Canadian oil may be lifted -- or at least very substantially liberalized -- in the near future. As overall U.S. import ceilings are raised and Canadian imports take on increasing importance to U.S. security of supply, this would be a logical step, but just when policy changes will be effected to accord with longer-run considerations is difficult to predict.

31. The freeing of imports from Canada would obviously be favorable for the near-term prospects of Canadian oil in U.S. markets. Many U.S. refiners are facing serious difficulties in getting access to sufficient volumes of domestic crude oil and are not strategically located to receive offshore oil. For many of these refiners, Canadian crude looks to be the only source of supply to offset declining domestic supplies and meet increasing refinery requirements. This includes refiners as far south as Colorado and Kansas, for example, who have been using Canadian oil as a source of supplemental supply, despite substantially higher delivered prices than for domestic crude. Thus, in the short run, demand for Canadian crude in the United States is expected to be very strong -- almost irrespective of price. If imports

from Canada are freed or substantially liberalized, the level of Canadian oil exports to the United States in the near term would be basically a function of the ability and willingness of Canada to deliver.

Longer-Run

32. Looking to the longer run, Canadian oil should continue to be a preferred source of U.S. oil imports. As with domestic oil, it is also in the long-run interest of U.S. policy to provide markets and remunerative prices for Canadian oil supplies. Canadian oil will contribute importantly to U.S. balances and higher Canadian prices for Canadian oil will, in course, favor intensified exploration, as in the United States.

33. With the outlook for sharply rising U.S. import volumes, the United States will probably be interested in importing as much oil from Canada as Canada will make available at least through 1980. However, even over the period of the latter 1970's, there could be some uncertainty as to import demand, depending upon the success of the United States in finding new domestic oil reserves and the integration of new sources of domestic production into markets.

34. If the Alyeska pipeline had not been held up, the initial movement of North Slope crude might have had at least a temporary effect on the rate of Canadian oil exports to the United States. However, pipeline issues still remain unresolved and now by the time North Slope crude begins moving, it by itself looks to have little impact on overall Canadian exports. To the extent Canadian oil may be backed out of Puget Sound, those volumes will find outlets in the Midwest.

35. Looking beyond Prudhoe Bay, however, there is the possibility that the United States may establish substantial reserves and production in other frontier areas. As noted earlier, Prudhoe Bay itself represents only a small part of the prospective acreage on Alaska's North Slope and other large sedimentary basins in Alaska have barely been explored at all. Large areas offshore the east coast of the United States represent another unexplored potential.

36. All this is not to say that new large-scale production will be established in various U.S. frontier areas. But it is likely over the long run that new prospective areas will be opened up and U.S. policies will provide incentives to explore these areas. And success might be forthcoming in one or more areas. After all, no one could really have foreseen Prudhoe Bay with any degree of confidence -- as also, for example, the North Sea, and now the promising potential of the Mackenzie Delta and the Arctic Islands. Thus, by the latter 1970's and early 1980's, one cannot rule out the possibility of major new U.S. production which could have an impact on U.S. oil imports from Canada -- at least a significant impact on increases from year to year.

37. In view of the uncertainties, timing could play a major role in the market prospects for Alberta tar sands oil, as well as other potential new sources of Canadian oil. The earlier tar sands oil moves to market, the less likely it is to face competition from other sources of North American supply and the greater the demand for it is likely to be. More important, the earlier tar sands oil moves to market, the more likely it is to warrant treatment as "base-load" supplies, insulating it from the potential impact of new large-scale production from other North American producing areas (of which more in Section IV).

Development of U.S. Synthetics

38. Alberta, of course, does not have a monopoly in North America on large resources that could provide synthetic oil. The United States has vast reserves of both shale and coal which have the potential of large-scale production of liquid hydrocarbons.

39. As yet, the United States does not really have a comprehensive policy for development of synthetic oil production from either shale or coal. However, sharply rising U.S. oil import requirements and increasing awareness of the uncertainties surrounding the future terms and conditions of availability of foreign oil have made it clear that U.S. synthetics are essential to the long-run security of U.S. energy supplies. Even though the technology and economics of synthetics are somewhat uncertain at the present time, the resources are known and large-scale production is a reasonable certainty over the long run if adequate incentives

are provided. In view of the long time lag in research and development, however, an early start will be required if the United States is to count on oil from shale and coal making a significant contribution even by the mid and latter 1980's.

40. Given the importance and the urgency, it is likely that the United States will adopt policies in the relatively near future designed to encourage the development of synthetics. Direct government funding for research into new technology and process improvement may be accelerated. Leasing policies for shale and coal lands could be established so as to permit large-scale commercial operations.

41. Tax incentives for private investors in synthetic oil development are also a possibility. Relatively rapid amortization of investment might be considered, especially in view of the possible obsolescence of technology over a relatively short time. Beyond this, an investment tax credit could, in effect, lower the capital cost of synthetic oil ventures and, apart from reducing losses, would enhance the potential returns on risky investment where the venture may prove marginal.

42. The enactment of tax incentives for synthetics may prove politically difficult in the near term in view of widespread concern with closing tax "loopholes." However, such incentives might be feasible as part of a broader package which would eliminate or modify some of the present tax advantages provided for the U.S. oil industry. For example, the United States might shift from the current percentage depletion allowance -- which is at best only an indirect and relatively inefficient incentive for exploration -- to a concept of earned depletion, as is being adopted in Canada. Such a shift plus specific tax incentives for synthetics would reorient U.S. tax policy more closely in line with the Nation's vital needs for resource development.

43. Incentives beyond those above might also be considered if they are needed to spur development. The need for synthetic oil is certain, but when U.S. crude oil prices will rise high enough to support commercial production is uncertain. One possible measure to handle the price uncertainty would be some form of price guarantee, at least for early projects. This need not be a subsidy ensuring the profitability of these ventures, but only a limited guarantee of a minimum price until market prices reach a certain level.

44. In any event, it would seem likely that U.S. policy will recognize the development of synthetic oil from shale and coal as important to the long-run security of U.S. energy supplies. The exact nature of policies and their timing remains uncertain, but could obviously bear importantly on the pace and scale of development.

Tar Sands versus U.S. Synthetics

45. The future demand of the United States for secure sources of oil is so large that the United States will look to all potentially available North American resources in due course. From the U.S. standpoint, the Alberta tar sands would appear to be at least as important as its own domestic synthetics from shale or coal. As with shale and coal, known tar sands reserves are very large relative to conventional North American crude oil reserves and potential levels of production could eventually make a major contribution to North American oil balances. It is not the lack of reserves that has inhibited the development of any of the North American synthetics, but in fact the magnitude of the reserves has been the major stimulus to projects for exploitation.

46. In terms of potential timing -- which could be very important to the United States -- the tar sands would seem to have a considerable leg up on U.S. oil shale and coal liquefaction. By way of example, the NPC intermediate supply cases (II and III) project the following for U.S. oil shale* --

1978-1981, one plant producing 100,000 barrels daily;

1982-1983, one more plant of 100,000 barrels per day; and

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* According to the NPC, "assuming a favorable attitude regarding the environment and the necessary community development to assure the necessary manpower supply, this is the potential development rate with the number of companies holding sufficient reserves and the capital requirement placed upon them. Furthermore, under the conditions assumed to prevail for the base case -- i.e., minimal changes from policies, practices and economic climate existing at the beginning of the study period -- only a token volume of syncrude from oil shale is projected to be developed from private lands and only one 100 MB/CD plant is expected to be operating by 1985."

1984-1985, two additional plants of 100,000 barrels daily each, or a total of 400,000 barrels per day by 1985.

Production of coal-based liquids is projected even further into the future by the NPC, with no commercial production in 1980 and only some 175,000 barrels daily by 1985.*

47. In contrast, the first Alberta tar sands plant went into production some five years ago. If it moves ahead on schedule, the Syncrude facility could begin production in 1976 and reach design capacity by 1977 or 1978. Projections by the Alberta ERCB indicate that three in-situ schemes and one or two additional mining projects might be undertaken over the period 1977-1982, with total tar sands production in 1982 in the range of 375,000 to 650,000 barrels per day. By 1985, estimates of potential production from the tar sands run as high as 1.25 million barrels daily from 10 installations (NPC Tar Sands Task Group).

48. While all projections of synthetic production are obviously subject to considerable uncertainty, the concensus of opinion is clearly that the Alberta tar sands offer the prospect at least of larger volumes of production at an earlier date than U.S. oil shale and coal liquefaction. The basic reason is the much earlier start taken to develop the tar sands. The first commercial venture in oil shale from which later ventures can benefit apparently will not come onstream until at least a decade after the first tar sands plant; for coal liquefaction, it looks to be even later. All of this is not to say that tar sands technology is well established and that all uncertainties are gone. But the uncertainties with tar sands are probably considerably less at this point in time than for U.S. synthetic oil from shale or coal.

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* NPC supply Cases II and III; Case IV does not project commercial production even by 1985. The NPC states that "technology for economically producing coal-based liquids is not available today. Maximum projected output of coal-based liquids is 680 million barrels per day under Case I. To approach such a level of production would require an immediate decision to proceed with the design and construction of a first demonstration liquefaction plant. This would be a high-risk plant because technology is now only partially developed. (Under current economic conditions, the incentives to develop and build such a plant do not exist.)"

49. In view of the potential contribution tar sands supplies could make to North American oil balances relatively soon and with a reasonable degree of certainty, U.S. policy has an obvious interest in seeing the development of Alberta tar sands pushed ahead at a rapid pace. We turn next to policy issues on the Canadian side.

Canadian Policy Issues

50. The concerns of Canadian oil policies are shifting with the changing circumstances of the Canadian oil industry. In the past, the problem has been one of finding adequate markets for Canadian oil resources. At least for the years immediately ahead, the problem will shift to one of meeting all the demands upon Canadian reserves and controlling the volume of oil exports in order to assure supplies for the domestic market. For the longer run, there is the question of the extent to which Canada should develop its own resources for export markets.

National Oil Policy

51. Canadian National Oil Policy was set out in February 1961, following the Report of the Royal Commission on Energy which considered, *inter alia*, the prospects for Canadian producibility and production in the light of Canada's long-range potential. Targets for Western Canadian production were set as a matter of policy -- 640,000 barrels daily in 1961, rising to 800,000 barrels per day in 1963, with reasonable growth thereafter.

52. These production goals were to be achieved in part through normal growth of demand in areas then supplied by Canadian oil. Beyond that, growth was to be achieved by pre-empting the entire Canadian market west of the Ottawa Valley, which meant displacing a substantial volume of products processed from foreign crude in Montreal refineries with products processed from Western Canadian crude in Toronto refineries; and by increased exports to the United States.*

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* In 1961, Western Canadian crude was at a competitive disadvantage in U.S. markets, compared with U.S. crudes. Accordingly, the responsibility for insuring export volumes was placed upon eastern Canadian refiners; in effect, their continued free access to foreign crude was conditioned upon Canada's production and export objectives being met. Subsequently, Western Canadian crude realized a significant competitive advantage in U.S. markets proximate to pipelines from Canada, owing to reductions in Canadian pipeline tariffs, disparate adjustments in Canadian and U.S. wellhead prices and, in earlier years, to exchange adjustments favorable to Canadian oil. This competitive advantage provided a very significant spur to demand by U.S. refiners for Canadian crude.

53. Over the years since 1960, increased exports to the United States have accounted for the largest part of the total rise in Canadian production. Between 1960 and 1972, Canadian production of crude oil and crude oil equivalents increased rapidly from 530,000 barrels daily to 1,700,000 barrels per day, a gain of 1,170,000 barrels daily -- of which 835,000 barrels per day represented increased exports to the United States and 330,000 barrels daily increased demand by Western Canadian refineries. In course, exports rose from around 20 per cent of Canadian production in 1960 to some 56 per cent by 1972.

54. Through 1966, despite the relatively rapid build-up in production and market outlets, production of Canadian crude did not keep pace with the development of Western Canada's crude resource base -- the reserves-to-production ratio rising from 17 years in 1956 to 25 years in 1966 (34 years in Alberta). Since 1966, however, production has grown faster than reserves, with the ratio of reserves-to-production in Western Canada declining to an estimated 13-14 years in 1972 (17-18 years in Alberta).

55. Thus, the circumstances of Canadian crude production have changed very considerably. In the past, the concern of Canadian oil policy had been to ensure adequate outlets for Canadian crude, so as to increase rates of utilization of reserves and thus provide incentives to further exploration and development. But for the time being at least, the question of access to U.S. markets has been largely laid to rest. In Western Canada -- and Alberta in particular -- the problem has shifted from one of inadequate markets and the need to prorate production to available demand to the development of productive capacity to meet potential demand.

56. From the broader Canadian standpoint, however, the opening up of the U.S. market raises a new potential problem -- that of assuring adequate crude supplies to Canadian refiners operating on Canadian crude. As noted, even with the latest Canadian crude price increases, Canadian crude still retains a small margin of advantage in delivered cost over U.S. crudes in major refining centers on the northern perimeter of the United States. Furthermore, refineries in various areas of the United States have been experiencing difficulty in getting access to crude supplies adequate to meet requirements regardless of price. While U.S. import policy can be expected to make enough crude available to meet overall U.S. refining requirements, short-term logistical problems are likely to continue to plague

various refiners. Many of these U.S. refiners should continue to look to Canadian crude to balance requirements even where its delivered cost exceeds by a significant margin the cost of domestic crude (e.g., in the Mid-Continent area). As of now, the demand for Canadian crude exceeds the supply and this could continue to be the case for some time.

Export Controls

57. If the United States continues to set quotas on imports of Canadian crude, the flow of Canadian crude into U.S. markets should be held to levels that do not pose problems on the Canadian side. However, if quotas are lifted -- and absent some other control mechanism -- there could be a competitive scramble by U.S. refiners to obtain access to whatever volumes of Canadian oil are available. This obviously raises the question of how Canadian refiners may fare in obtaining the volumes of Canadian crude they require. In order to assure Canadian refiners with adequate supplies, export controls of some type might be required.

58. Absent quotas on Canadian imports, control over the flow of Canadian oil to U.S. markets might be handled on an informal basis, either by U.S. or Canadian authorities or both. For example, this might take the form of pressures on U.S. refiners to keep their requests for Canadian crude reasonably in line with the capabilities of the Canadian industry to deliver.

59. If more formal control is required on the Canadian side, the exact form that such export controls might take is somewhat uncertain. The NEB Act provides that "gas or power" cannot be exported except under the authority of a license issued by the NEB and sets out criteria for approval of applications for such export. However, the Act also provides that the same provisions applying to gas or power exports can be extended to oil exports by proclamation of the Governor in Council.* Upon issue of such a proclamation, the term "oil or gas" shall be deemed substituted for the term "gas" in Part VI of the NEB Act dealing with exports.

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* The Act also provides for revocation of such a proclamation by Parliament.

60. On this basis, the Act would set out two criteria for approving an export license for oil --

> The quantity of oil or gas or power to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of oil or gas in Canada; and
>
> The price to be charged by an applicant for oil or gas or power exported by him is just and reasonable in relation to the public interest.

In addition, the Governor in Council may "by regulations exempt any class of oil or oil products or any area from the operation of all or any provisions of this Part [dealing with exports]."

61. The criterion set out in the NEB Act for approval of export volumes is obviously very broadly worded (as also the criterion for export prices). However, an assessment of the adequacy of Canadian resources to meet future Canadian requirements would probably consider potential production from conventional crude oil reserves, including reserves in being plus some allowance for future finding, and tar sands production, including both extant projects and authorized projects that could be anticipated with reasonable certainty.

62. On this basis, a firm program for tar sands development could change very significantly the future supply picture that the NEB would be looking at in establishing export volumes. Such a program could serve to take considerable pressure off conventional Western Canadian crude to hold reserves for future Canadian requirements. Thus, in the future, the impact of tar sands oil on conventional Alberta crude production could be just the opposite of the effect in the past. When demand for Canadian crude fell short of productive potential, the concern always was with the potential adverse effect of tar sands production on rates of utilization of conventional Alberta crude, which acted as the "balance wheel" in Canadian producing operations. In the future, however, with demand exceeding productive potential from conventional reserves, tar sands projects might provide reserves and future production needed to assure future domestic requirements. On this basis, new tar sands projects might actually contribute to higher rates of utilization of conventional Alberta crude.

Development for Export

63. Within Canada, there is increasingly sharp debate over the desirability of large-scale development of oil and gas resources for export. In the past, the desirability of resource development had been accepted almost without question. Now, doubts are beginning to be expressed -- by what is undoubtedly still a minority, but still an increasingly vocal minority.

64. The opponents of maximum resource development argue that Canada's known reserves of oil and gas are already adequate to meet Canada's own requirements for many years to come. Further development to meet domestic needs would be comparatively modest and thus the pressure to develop resources comes largely from increasing U.S. import requirements.

65. The argument then seems that resource development entails serious problems for Canada, including:

> Damage to the environment, which may or may not be reversible;
>
> Huge financial demands for required capital investments -- which would have to be largely met by foreign funds, driving up the exchange rate for the Canadian dollar and limiting the competitive capabilities of Canadian manufactured goods in world markets and to the extent financed within Canada, would drive up the cost of capital and draw capital away from other areas of investment deemed more desirable; and
>
> Increased control by U.S. firms over the Canadian economy.

Against these negative aspects, the potential benefits to Canadian citizens in terms of employment opportunities, governmental revenues, and collateral industrial development are seen by the opponents of resource development as comparatively modest.

66. Proponents of resource development have rebuttals to these arguments. They argue, for example --

> The industry has become increasingly concerned with environmental problems and is capable of successfully coping with them;
>
> Large inflows of foreign capital need not necessarily lead to higher exchange rates for the Canadian dollar, depending on how they are handled;
>
> Overall benefits of resource development to the Canadian public are considerably greater than detractors suggest; and
>
> Resource development does not really have to be alternatives to development of other industries at the same time.

67. It is not our remit to assess the merits of the case for or against resource development for export. In the context of the debate, however, tar sands projects would presumably meet the criteria of Canada's interests -- as well as the interests of the Province of Alberta -- at least as well and probably rather better than Arctic oil and gas development. The environmental problems posed by tar sands development would certainly not appear to be more difficult than those of Arctic development and transportation. From a social and economic standpoint, direct employment in tar sands operations would appear to compare favorably with conventional oil and gas production. Tar sands projects are probably capable of supporting at least small-scale permanent population centers. While the area of tar sands deposits is a frontier, it is not an unmanageable frontier and would offer greater prospects of providing a reasonably inhabitable environment than Arctic areas. Tar sands development may also provide greater opportunities for collateral industrial development.

68. What comes out of all of the above discussion of policy issues is the advantage of moving early and rapidly to develop tar sands production. From the U. S. standpoint, early development of the tar sands could contribute to the availability of secure North American oil supplies over the critical period before its own long-run efforts to develop conventional and synthetic oil might begin to pay off. From the Canadian side, the establishment of early and substantial volumes of tar sands production could be

essential to maintenance of Canada's export potential, providing an offset to Canada's rising volumes of oil imports. For both the United States and Canada, rapid tar sands development would provide "third generation" plants by the latter 1980's or so and an earlier fix on the long-run cost of North American synthetic oil production.

69. While this is a strategic time to push ahead with tar sands development, there is always the possibility that large-scale production from the tar sands could result in less-than-optimum utilization of conventional Alberta oil at some time in the future -- e. g., if major oil production is established in the Mackenzie Delta and/or the Arctic Islands. However, this is a development that obviously cannot be predicted. Furthermore, in view of the overall outlook for North American oil balances, the impact of tar sands production on conventional Alberta oil would probably be relatively limited in degree and duration -- if it were to have an impact at all.

IV. IMPLICATIONS FOR TAR SANDS DEVELOPMENT

1. In the preceding sections, we considered the major external factors which will bear on the prospects for tar sands oil. In this final section, we turn to a look at the implications of all these for interest in tar sands development and a Provincial policy for the tar sands. We begin first with a review of certain background considerations dealing with tar sands operations themselves -- costs, royalties, and financing. This is not part of our remit, but some key conclusions with respect to these factors are pertinent to what follows. Then, we look at various parties that may have an interest in tar sands development, considering both their incentives to participation and their potential contribution as participants from the standpoint of the Province. Finally, we consider the interests of the Province in several key aspects of tar sands development.

Costs

2. At this point in time, the costs of producing tar sands oil are uncertain and it would be difficult if not impossible for anyone to predict with any degree of precision what future costs will be. In any event, even if it were possible to project future tar sands costs, this is not really our area of expertise. However, out of all the uncertainties, there are certain significant implications.

3. Tar sands technology is still in the relatively early stages of development and experience with commercial-scale operations is limited. Costs for various tar sands projects will vary depending on the approaches and technology employed. The costs of alternative schemes will not really be known until they are tried on a commercial scale. Thus, the experience of a number of initial approaches could be important to the success of second-generation projects. Given the current favorable environment for tar sands development foreseen in preceding sections, this would be the opportune time to move forward with projects that explore various approaches.

4. For at least first-generation projects, tar sands output will be essentially a "price taker" in North American oil markets. That is, tar sands output will realize a value determined by the price of other major crude streams, allowing for differences in transportation costs and quality (which as noted earlier, could be quite favorable for tar sands oil). In these circumstances, the costs of producing tar sands oil will bear directly on the profitability of tar sands ventures.

5. Given the present margin of uncertainty over costs and also future North American oil prices, early projects could obviously turn out to be much less profitable than anticipated, as witness the first GCOS facility.* At this stage in the game and for some time to come, a tar sands project would have to be considered an investment with a fair degree of risk. Given the risk, participants in early tar sands projects would expect relatively attractive rates of return on successful projects, as they would on successful conventional oil exploration. Over the longer-run, however, when technology and costs of tar sands production are reasonably well established, rates of return on investment in tar sands projects are likely to be closer to returns in manufacturing industries than to returns on successful exploration ventures. Average rates of return on tar sands projects should be reasonably comparable over the long run with average returns on total industry investment in conventional oil exploration/production, including both successes and the large number of exploratory failures. But as the risk in tar sands development is reduced over time, returns on individual tar sands projects should become considerably less variable than on individual exploration ventures.

6. Second-generation plants could be making a major contribution to Canadian oil production by the late 1980's and thereafter. During this period, the economic attractiveness of the tar sands will become somewhat clearer. If tar sands oil is still a price taker, price/cost relationships as they appear at that time would bear importantly on the incentives to third-generation plants.

7. On the other hand, as noted earlier, it is even possible by then that the costs of tar sands and Canadian Arctic production might play a role in the determination of North American crude oil prices. If this were to turn out to be the case, relatively high costs for new incremental sources of Canadian oil would not be an inhibiting factor in future development. Incremental volumes would be essential to North American requirements and prices would have to be high enough to subsume the costs of development and production plus a reasonable rate of return.

8. Costs will also obviously bear upon Provincial royalties. In the short run, high costs may pose problems of setting royalties that do not unduly burden the economics of initial plants. Over the long run, with the emergence of a more stable and predictable cost basis, costs will be a major factor in the determination of a royalty policy that optimizes the Province's economic interest in some 350 billion barrels of recoverable tar sands oil reserves, which the Province could make available to meet North American oil requirements.

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* As noted in Section III, there are also some uncertainties as to the quality of tar sands oil, which would also bear upon projected versus actual profitability.

Royalties

9. In principle, a royalty policy should meet two broad criteria. On the one hand, after payment of royalty, producers should still have reasonable incentives to construct and operate tar sands facilities. On the other, the Province, as owner of the tar sands, should receive a payment that reasonably reflects the value of the resource. However, in view of the present stage of tar sands development and the uncertainties over future costs and prices, it would seem virtually impossible to establish a royalty now that would be equitable to both producers and the Province for all future tar sands projects or even for the remaining life of the project now in operation.

10. While it could be many years before enough is known about tar sands operations to develop an appropriate long-run basis for royalties, projects approved and operating in the interim will have to pay royalties on some basis. Two approaches might be considered to the establishment of interim royalties. One would be to set royalties for early plants on a project-by-project basis, depending upon technical specifications and cost projections. These interim royalties would apply for a given number of years and then would be subject to review in the light of longer-run royalty policy (of which more below).

11. Another approach to the setting of interim royalties might be to establish a general royalty that would be relatively attractive to producers and which would apply to all production prior to a certain date. This could provide an incentive to early tar sands development, since the benefits to an individual project would depend upon how many years it came into production before the cut-off date.

12. Under any type of interim royalty arrangements, there would also have to be a reasonable degree of assurance that longer-run royalties would not be set in the range that would impinge on the viability of projects after the investment has been made. Otherwise, financing might be difficult to arrange. Thus, it would be essential to set out at least some general principles governing longer-term royalties at the outset.

13. In broad form, tar sands royalties would presumably be assessed as a per cent of the value of output, the traditional form of royalty on natural

resource leases.* This form of royalty has the advantage of scaling royalty payments up or down, depending on the relative quality of the resource. It also results in both producer and landholder automatically sharing in any general increases in resource values.

14. The question of how to determine the value on which tar sands royalties should be assessed is a difficult one. In principle, the value of raw bitumen extracted from the sands would appear to be the appropriate concept. Any value added beyond that point is essentially through a refining or manufacturing process. However, as of now and for the foreseeable future, tar sands projects will be integrated operations, combining both extraction of bitumen and upgrading of bitumen to a marketable product. In these circumstances, bitumen itself does not have a value that can be established in the market place.

15. Thus, barring the development of a commercial market for raw bitumen, its value can only be established by reference to the market value of the final products that move out of a tar sands facility, with allowance for the costs of processing or upgrading. The market value of final products is likely to vary among projects, depending upon the quality of the reserves and the processing techniques utilized. These differences in value would presumably carry through to the value of the bitumen.

16. Once the tar sands industry has developed and there is a reasonable body of experience to draw upon, average processing costs (including reasonable return on investment) would be the appropriate concept to apply in netting back the market value of final products to the bitumen level. Over the long run, it will be average costs that in fact determine how much bitumen is worth, not the uniquely high or low costs of any particular facility. The Province will want a long-run royalty that reflects the general value of the resource, not the particular economic circumstances -- good or bad -- of individual projects.**

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* Permits specify that royalty on tar sands leases will not exceed certain percentages of the "products derived from bituminous sands or oil sands." On permits issued prior to August 31, 1956, the maximum was 10 per cent; on permits issued later, 16 2/3 per cent.

** One exception would be where the imposition of full royalty would result in the premature abandonment of operations. It would not be in the interest of the Province to have a tar sands plant shut down if a reduced royalty would keep the facility in production. However, if such a case were to arise, the Province would obviously have to look very carefully at the circumstances to see if reduced royalties would be warranted.

17. Until costs become more certain, tar sands royalties may have to allow for actual or projected costs of individual facilities. But to do so after costs are reasonably established would make the royalty, in effect, a form of income tax. On this basis, the Province would stand to share substantially in unusually successful projects, but would also subject the Province to the risks of very little or nil royalties on less successful projects. These are the rewards or penalties that producers should earn, not the owner of the resource. The Province should be entitled to a reasonable royalty that reflects the general value of the tar sands, not any more nor any less.

Royalty Rates

18. It is not part of our remit to recommend a policy on tar sands royalties or to suggest appropriate royalty rates. However, we have been asked to provide data on royalty and tax payments on producing operations in the United States. Royalties and taxes in the United States obviously have some relevance for a tar sands royalty, but there are also significant differences between conventional oil producing operations and tar sands production which would bear importantly on a royalty policy for the tar sands. We confine our comments here to a few general observations, providing a detailed review of taxes on production in the United States in Appendix F -- Production and Severance Taxation in Major Producing States of the U.S.

19. In Alberta, royalties have historically represented the only direc payment on producing operations, although recent revisions in Alberta policy introduced a tax on reserves that would apply to leaseholders who do not opt for newly increased royalties. In the United States, in addition to royalty payments to landowners, oil producing operations in virtually all important producing states are subject to severance taxes (i.e., taxes on current production) and/or ad valorem taxes on producing properties. Summarizing briefly, in the four largest producing States -- Texas, Louisiana, California, and Oklahoma -- which account for four-fifths of total U.S. crude production, the rate of state severance and/or property taxation works out to around 8 per cent of the value of crude oil production. The rate of taxation in Alaska, which will become a major producing State when production begins from Prudhoe Bay, is in the same range.*

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* As discussed in Appendix F, the rate of severance taxation in Alaska depends upon wellhead price. At wellhead values of $2.65 per barrel or greater, the rate of taxation on a well producing 10,000 barrels daily (an estimate of average well productivity in the main producing reservoir of the Prudhoe Bay field) would be in the neighborhood of 7 to 7 1/2 per cent of the value of production. If the wellhead value were below $2.65, the effective rate of taxation would be higher.

20. Royalty payments in the United States average about 15 per cent of the gross value of production.* Thus, the total burden of payments to landowners and taxing authorities on oil-producing operations in the United States comes to approximately 22-23 per cent of the value of production of the wellhead.

21. The new royalty for conventional crude oil production in Alberta -- which applies to all new leases and to old leases unless a producer opts to pay the tax on reserves -- is a step schedule with well production, ranging from 16 2/3 per cent up to 25 per cent. The average royalty rate under the new schedule is estimated at about 21 per cent -- or slightly below the average combined royalty/tax rate in the major producing states of the United States.

22. However, while this comparison of rates is a relevant one for conventional Alberta crude oil, it cannot be assumed that it is directly transferable to a comparison of a tar sands royalty with royalties on alternative and competing sources of refinery feedstocks. The circumstances of tar sands production are quite different from conventional crude oil. In conventional operations, it takes extensive exploration to discover reserves; in tar sands operations, reserves are largely known at the outset. Crude oil development and production is very different from mining operations for tar sands or even from in situ production, which does involve drilling and producing wells. The complex processing that must be done to upgrade raw bitumen to a usuable product represents something not found in conventional production, being more akin to crude oil refining.

23. In view of the different nature of conventional versus tar sands operations, relationships between prices or values and costs may also be quite different. Tar sands development is considerably more capital intensive than conventional oil-producing operations. Furthermore, rates of return on investments in tar sands facilities over the long run when technology is reasonably well established are likely to be closer to those in manufacturing industries than to the high rates of return common to conventional oil producing operations (which represent only the successful oil exploration efforts). As a result, the potential impact of a given royalty rate on the economics of tar sands production may also be very different from the impact on conventional crude. Thus, royalty rates on conventional crude must be used with considerable caution as guidelines to an appropriate tar sands royalty.

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* This is an average for total U.S. production. The royalty rate on Federal offshore leases is 16 2/3 per cent and a 16 2/3-per-cent rate is also common for better onshore prospects in Texas and Louisiana. Royalties on some state offshore leases in California have been even higher. However, a 12 1/2-per-cent royalty is still typical in many other areas, including state leases in Alaska.

Financing

24. To the extent that the emerging environment is as discussed earlier and U.S. and Canadian Federal policies are conducive to tar sands development, problems of financing would not look to be intractable for the pace and scale of development that may be practical from a technical standpoint. The capital costs of investment in tar sands development will be very large. Furthermore, they will come at a time when the industry will also be faced with tremendous capital needs for other purposes as well -- e.g., several multi-billion dollar oil and gas pipelines from the Arctic, huge exploration and development outlays in both frontier and established areas of North America, and major expenditures to catch up with lagging refinery construction in the United States.

25. However, among all these competing demands for capital, tar sands development is not at the bottom of the list of priorities by any means. As will be discussed, various parties are likely to have a strong interest in participating in tar sands development in order to bolster their long-run position in North American resources. From the standpoint of the U.S. and Canadian Governments also, development of the tar sands would look to be of vital concern for the various reasons set out earlier.

26. The ability to finance tar sands projects may be very different, depending upon the participants. For major integrated oil companies, financing can be arranged on the basis of the whole equity position and borrowing power of the corporation itself, rather than the unique circumstances and risks of a tar sands project. The various foreign companies that might participate would have considerable financial support from their home governments, either directly or indirectly. However, various other potential participants, especially Canadian independents, could face difficulties in financing a tar sands project where the magnitude of the financial contribution looms very large in the context of their overall capital capabilities. This could be a particular problem for independents attempting to put together a project by themselves or even through a grouping of independents. However, as participants in a broader corporate grouping, independents would probably have a much better chance of arranging necessary financing, especially if market outlets could be assured through long-term supply contracts with major-company partners or even armslength sales to outsiders.

27. While the problem of financing cannot be passed off lightly, it does not look like something that should be the single most important criterion in a tar sands policy. Financing should not be an inherent problem that will hinder tar sands development. However, in the event financing should pose serious difficulties, the broader interests of the Province would have to be considered and the ability to finance projects could take on added importance in the selection of projects.

Parties of Interest to Development

28. Various different types of companies may have an interest in participating in the development of the tar sands. We consider first the incentives of these various parties to participate and then their potential contribution from the standpoint of the Province.

The Integrated Majors

29. In general, major integrated oil companies -- i.e., large-scale companies which have interests in both oil resources and refining/marketing -- would have a considerable incentive to participate in the development of the tar sands. All of these companies have a basic interest in a strong resource position to support their heavy investment in downstream operations. This reflects the nature of the distribution of integrated profits within the oil industry. Downstream margins have historically been very precarious, with access to crude oil essential to overall profitability.

30. The majors look to increasing opportunities to process their own foreign production in their North American refineries over the years ahead, permitting them to capitalize on the profitability of their foreign producing position. However, as noted, over the longer run, both the cost and tenure of foreign oil looks to be increasingly uncertain. As control over reserves becomes less certain in foreign areas and their status as privileged offtakers is eroded, the majors are likely to be increasingly interested in access to North American reserves to meet their North American crude requirements.

31. With respect to North American supplies, the majors are probably convinced that governmental policies over the long run will be designed to ensure access to markets for indigenous resources that are developed and at prices which will permit reasonable returns, given the risks involved. North American oil will move into North American refineries -- as a matter of governmental policy if not of free-market economics. If the majors have to process North American oil in their facilities, they would rather be the producers of that oil than have to purchase it from others. For the integrated company, owned oil is almost always preferable to purchased oil, because of the margin of profit and cash flow from production. Furthermore, a major company can be at a considerable disadvantage in product markets if it has to compete on the basis of purchased oil against competitors who have access to cost oil. Even worse is the prospect of competing in product markets on the basis of oil purchased from competitors.

32. While all of the major integrated companies are likely to have a potential interest in the tar sands, there are differences among these companies -- particularly with regard to their resource positions. Those who are already deficient in North American crude oil production and are net buyers of crude could have a special interest in the tar sands. As imports open up, these companies will have recourse to substantially larger volumes of foreign oil, which for most would be their own integrated foreign production. However, overall proportions of offshore versus North American oil that will meet U.S. oil requirements are likely to be set by U.S. policy and it is unlikely that any one integrated company will be able to import directly a disproportionate share of foreign oil to meet his own refinery requirements. As a result, crude-short refiners will probably not be able to make up their deficiencies through a disproportionate percentage of imports.

33. Various refiners who are crude short and do not have access to new streams of crude that might improve their integration ratios have already been active in the tar sands. For example --

Sun owns most of the initial Great Canadian Oil Sands venture;

Cities Service is a participant in Syncrude; and

Indiana holds substantial tar sands permits and is working on in situ processes to develop its resources.

Even Arco, which has large-scale reserves in Prudhoe Bay that will eventually improve its producing position very substantially, has nonetheless been heavily involved in development of synthetics production, including an interest in Syncrude and in The Oil Shale Corporation (TOSCO).

34. Other major integrated companies that are now reasonably in balance in North American oil supplies but lack a really strong position in new areas -- e.g., Shell and Texaco -- have also shown an interest in tar sands. Shell has done substantial research in both strip mining and in situ recovery methods and applied several years ago to move ahead on a commercial-scale project. Texaco is involved in a pilot project utilizing in situ techniques. Even a company such as EXXON, which is now reasonably in balance in North American crude supplies and has a strong position in frontier areas (major reserves at Prudhoe Bay and significant discoveries in the Mackenzie Delta) is interested in moving ahead on tar sands development as a participant in Syncrude.

35. Thus, virtually none of the major integrated companies feel that they can be completely left out of the tar sands, which looks to become a major new source of North American oil production. If they lag far behind their competition in access to North American production, they cannot realistically expect to make up the difference through differential access to foreign oil -- which in any event is subject to considerable uncertainty as to tenure and profitability over the years ahead.

36. As the shortfall in North American resources, the prospect of substantially higher North American prices, and the uncertainties of foreign oil have become more and more evident, the major integrated companies have moved into areas of North American resource development which they had previously avoided. For example, where once the majors had exhibited varying degrees of interest in such frontier areas as the Arctic Islands and the Mackenzie Delta, now with the passage of time all are participating. The major integrated companies have a similar interest in participating in commercial tar sands ventures.

Canadian Independents

37. Various Canadian independents will also be interested in participating in tar sands development. Their interest in tar sands has already been evidenced by the acquisition of permit acreage. The ability to contribute leases could provide the independents with leverage in obtaining direct participation.

38. For the independents, tar sands development is quite different from the conventional oil exploration plays that have been their primary business. First, the financial requirements are of a much larger scale. In Alberta and the other Western provinces, costs of entry in terms of bonuses and exploration outlays are of a scale that independents could participate, either by themselves or with others. In the frontier areas, the Canadian independents were able to establish an early acreage position (notably in the Arctic Islands), with later participants such as major-company farmees or U.S. gas companies providing the bulk of the large-scale financing required for exploration and development.

39. The expertise needed for tar sands development is also quite different from conventional oil and gas exploration that is the "stock-in trade" of the Canadian independents. Exploitation of tar sands consists not of finding reserves, but of developing the mining, extraction, and processing technology to convert the raw tar sands into a usable refining feedstock at prices that can compete with conventional crude.

40. In contrast to the major integrated companies -- who could be interested in access to reserves to support downstream requirements as well as direct profitability on sales of tar sands oil -- the Canadian independents would be primarily interested in direct financial rewards versus the potential risks. Furthermore, the Canadian independents do not have their own integrated market outlets for disposal of tar sands production. Thus, the independents would have an interest in obtaining long-term contracts, this probably being required to obtain the necessary financing. However, there should be possibilities for concluding armslength contracts with refiners who do not participate in the tar sands. From the standpoint of Alberta, such sales could certainly contribute to the valuation of tar sands output. Establishing a royalty value could be more difficult if all tar sands oil moves in integrated channels than if there are at least some third-party sales.

41. Technical and financial limitations could make it difficult for Canadian independents to enter commercial tar sands operations on their own. Even combinations of a number of independents could face similar problems. However, the independents could participate as members of broader corporate groupings which include major integrated companies who would provide the required technical expertise. Smaller-scale participations would probably be within the financial capabilities of various independents. Major company participants might also contract for the output of the independents, providing assured markets. But as noted above, this may not be necessary and might not even necessarily be desirable from the Province's standpoint if armslength sales arrangements could be concluded.

National Companies of Oil-Importing Countries

42. Various national companies of oil-importing countries -- notably from Western Europe and Japan -- may also have an interest in tar sands development.* A number of private oil companies from oil-consuming countries who are primarily engaged in refining and marketing have been looking to foreign oil exploration and development in an attempt to integrate upstream. These companies see access to owned crude as necessary in order to compete successfully with the international majors -- and increasingly also U.S. "independents" -- in home markets.

43. Governments of a number of oil-importing countries have sought to have a larger proportion of their oil imports met by supplies from national companies. To this end, they have encouraged overseas oil development by national companies, both indirectly through support of private companies and directly through state-owned or state-controlled oil companies. The reasons are several. First, oil imported by national companies can result in significant foreign exchange savings as compared with the full purchase price on oil purchased by national companies from foreign companies or the invoice price on oil imported directly by integrated foreign companies.

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* Appendix D deals with Foreign Exploration and Development by National Companies of Importing Countries. This Appendix reviews the general objectives of oil-importing countries and their national companies in foreign oil development, as well as the specific circumstances and scope of the major activities of the major Western European and Japanese national oil companies.

44. There is also a desire by importing countries for geographic diversification of crude supplies for home markets. While the international oil companies offer geographic diversification through their world-wide producing operations, diversification through national companies may provide an importing country with somewhat greater control over the origin of its oil imports. Where "secure" oil of national companies may have difficulty in competing for outlets, preferred access may be given in home markets.

45. Perhaps the most important reason for the interest of oil importing countries in direct access to foreign oil is that, rightly or wrongly, it is felt that "national" oil is somehow more secure than oil supplied by foreign companies to their local refining affiliates. "Political diversification" of imported oil supplies may be seen as at least as important as "geographic diversification."

46. Development of North American reserves -- including the tar sands -- could offer national oil companies of oil-importing countries another form of diversification.* Several of these companies have undertaken activities in Canada. For example --

> Deminex (a group of German independents, supported by the German Government in foreign oil development) has taken a farmout from Panarctic and has acquired other Arctic Islands acreage;

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* In assessing the potential interest of European and Japanese companies in North American development, it should be noted that recent and prospective developments in the Middle East may actually work to renew the interests of these companies in that area. In the past, European and Japanese companies have experienced real difficulty in gaining direct access to large established Middle East reserves. Where these companies have taken new exploration acreage, they have either been unsuccessful in finding reserves or have found only limited volumes of relatively high-cost oil. Now, however, with the erosion of the hold of the major international companies over Middle East reserves, European and Japanese companies may see greater opportunities to establish their own access to major reserves through new arrangements with Middle East governments. To the extent that this becomes their target, European and Japanese companies may perhaps be less willing to channel large investments into the tar sands.

The French state-owned ELF/ERAP has been active in Canada since 1962 and has widespread acreage holdings in Western Canada and in Canadian frontier areas; and

The Japanese Petroleum Development Corporation has undertaken small-scale exploration efforts in Western Canada.

47. Furthermore, some national companies of oil-importing countries have indicated an interest in development of North American synthetics. ELF/ERAP and SNPA (51-per-cent owned by ELF/ERAP) were early participants in TOSCO, which has been active in research and development of U.S. oil shale reserves. Recent press reports have stated that the French Government wants ELF/ERAP to consider tar sands development, as part of a larger effort to make up for loss of French production in Algeria. The Japanese have also expressed interest in Alberta tar sands development from time to time, although nothing definite has apparently come out of this potential interest.

48. While various national oil companies are seeking to develop diversified oil supplies, it seems unlikely that they would enter tar sands development with the idea of actually transporting tar sands oil to home markets, except perhaps Japan (of which more later). Neither Western Europe nor Japan is likely to be a preferred destination for tar sands oil. In these home markets, tar sands oil would have to compete directly with Middle East and other Eastern Hemisphere crudes at a substantial transportation cost disadvantage -- as contrasted with a substantial transportation cost advantage for tar sands oil in North American markets.

49. Furthermore, to the extent that tar sands oil is able to command a premium over and above the price of foreign oil for its "security value," that premium is likely to be higher in North America than in Europe or Japan. Europe and Japan are dependent on imported oil for a very substantial portion of their energy requirements and are vitally concerned with the security of imported oil supplies. However, if OPEC oil were cut off, these areas would be in very serious difficulty in any event and the volumes that imported tar sands oil might provide would not weigh very heavily in the balance. However, the United States and Canada have the potential at least

of developing North American oil resources adequate to meet a substantial portion of domestic requirements, an option not really open to Europe and Japan. A security premium for tar sands oil in Europe or Japan intended to draw in imports from secure sources is likely to be significantly less than a security premium in North America designed primarily to support a viable North American producing industry.

50. All this is not to say that some volumes of tar sands oil might not move to foreign markets. In particular, the Japanese have reportedly considered possibilities for moving tar sands oil to Japan. In the case of Japan, existing pipeline facilities already carry Alberta crude to the West Coast and the relative transport cost disadvantage of tar sands versus Eastern Hemisphere oil is less than in Europe. However, even for the Japanese, the cost would be high, involving a shift of tar sands oil supplies from markets where they would have their highest value to a market where their value vis-a-vis competitive crudes would be much lower. The Japanese would obviously have to consider carefully just how much of a premium they would be willing to pay for the kind of security direct utilization of tar sands oil might actually provide. Furthermore, the Japanese would probably want some type of long-run assurance from Canada that exports of tar sands oil (or other Canadian oil via exchanges) would be permitted to Japan. They would be especially concerned with access to Canadian oil during supply emergencies. In view of uncertainties over Canada's future export potential, Canada may not be willing to commit in-advance substantial volumes of its oil to the Japanese market.

51. However, even if national oil companies of importing countries do not think in terms of direct use of tar sands oil, they may nonetheless still be interested in participating in tar sands development.* While development of tar sands oil to be marketed in North America does not offer physical diversification in crude oil supplies for home markets, it does hold out the prospect of "financial diversification" of oil resources.

52. National companies and their home governments are concerned with the prospect of physical cut-off of supplies, but they are also concerned with the costs of their oil supplies -- both from the standpoint of

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* In this regard, it should be noted that national companies have in the past participated in North American oil development where there would be little likelihood that any production established would move to home markets. For example, ELF/ERAP holds exploration rights in the Western Canadian provinces, the Delta, Hudson Bay, and the Beaufort Sea -- all very distant from France. This Group also has participated in Western U.S. oil shale development, equally as remote. And Deminex has acreage on the very eastern flank of the Arctic Islands.

import costs to the country and the competitive capabilities of the national companies. Tar sands production could provide a national company with a financial hedge against rising oil costs in other areas, notably in OPEC countries. Increasing prices for their tar sands oil in the high-value North American market could be a significant offset to higher costs and prices elsewhere.

53. Furthermore, European countries have been concerned that the upstream profitability of the major international oil companies gives them a big advantage in competing downstream with European refining and marketing companies. And these countries have pointed in particular to the large profits earned by the major integrated companies in North American producing operations. Tar sands development could give European companies a foothold in North American production, bolstering their competitive abilities even in home markets.

The Interests of Alberta

54. In these final paragraphs, we consider the interests of the Province of Alberta in several key aspects of tar sands development that would be basic to a long-run policy --

Scale and timing of a development program;

Diversification among projects; and

Criteria for selection of participants.

Scale and Timing of a Development Program

55. As the preceding sections have indicated, emerging North American oil balances and the likely directions of public policy in the United States and Canada point to a very real advantage in moving ahead rapidly with tar sands development. Tar sands have the potential of making a significant

contribution to North American oil supplies in the period before other North American alternatives are likely to add substantially to availability. For the United States, tar sands production would add to the volumes of secure North American oil available in what will be a difficult period. For Canada, tar sands production could be a vital factor in the maintenance of an export potential in a period when domestic oil requirements are rising and conventional Western Canadian production looks to be peaking out.

56. The tar sands have already established an early lead over other North American synthetics in the development of technology and in experience with commercial-scale operations. Pushing ahead now could serve to maintain and perhaps even increase this lead. Alberta probably has the opportunity of developing second-generation plants by the time first-generation U.S. oil shale and coal liquefaction plants are coming onstream. And third-generation tar sands plants, which could be expected to benefit from relatively well established technology and perhaps important cost-savings, might be onstream by the time these other synthetics are in a second-round phase of development. On this basis, tar sands may be able to maintain a significant competitive advantage in North American markets for some time to come.

57. Early development of the tar sands could also be very important in establishing a "base-load" position for tar sands production. With the very large capital outlays required for construction of tar sands facilities, high rates of capacity utilization are essential to achieve reasonably low unit costs of production. Thus, the economics of tar sands operations virtually require that they supply a base load.

58. It is, of course, this feature of tar sands operations that in the past has been of concern to Alberta in authorizing projects. If tar sands plants must operate at or near capacity, it was conventional Alberta oil that would have acted as the balance wheel in Canadian oil production, suffering idle capacity if demand fell short of total supplies. As discussed, there is still the possibility that conventional Alberta oil could face less-than-optimum utilization at some time in the future if large-scale production is established in Canadian Arctic areas as well as from the tar sands. However, while this possibility cannot be ruled out, the chances of it happening now look relatively remote and any resulting reductions in conventional Alberta production would probably be relatively limited in degree and duration

59. It also must be recognized that the claim of the tar sands to a base load position in the future might not be as unique as it had been in the past. Arctic oil development entails very large investment outlays in production and transportation facilities. As with tar sands, the economics of Arctic oil also require both large-scale operations and relatively high rates of utilization of installed capacity. Thus, if Arctic oil production were to be established on a large scale in the 1980's, it could also claim the right to a base load position at that time.

60. All this is not to say that tar sands projects will face production cutbacks which could undermine their viability at some time in the future. In view of the contribution that tar sands production is capable of making to North American oil availability at a critical time, it is unlikely that either the Canadian or U.S. Governments would want to subject future tar sands production to uncertain market prospects, which could damage the incentives to development and perhaps even deprive North America of a vital source of oil.*

61. On this basis, special treatment for tar sands projects could be warranted under Canadian and U.S. policies. The participants in tar sands development would themselves seek to ensure the viability of their ventures by concluding long-term arrangements for disposal of output. Government policy would probably recognize such arrangements as having the attributes of a base load.

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* While future U.S. policies would seem to be pointing strongly in the direction of providing outlets and remunerative prices for North American oil production, there is always the possibility that the United States could in course decide that the prospects were so slim for attaining any meaningful degree of self-sufficiency that a continued effort was not worth making -- and, on that basis, open the doors to free importation of foreign oil. If the United States were to adopt this course as a matter of long run policy -- which would appear unlikely -- the incentives to then initiate new tar sands projects could be seriously diminished. However, in these circumstances, the economics of incremental costing and integrated operations should continue to support the viability of tar sands projects in process, with continued tar sands exports to the United States supported by existing long-term contracts. Insofar as incentives to North American exploration were reduced by the opening up of the U.S. market to foreign oil, conventional oil production in the United States and Canada could be expected to experience a long-run decline. The sum of Canadian oil requirements and contracted export volumes could probably then be adequate to provide outlets for both tar sands production in process and declining volumes of conventional Western Canadian production.

62. However, in achieving a preferred status, there is likely to be a real advantage in moving ahead as rapidly as practicable to build up tar sands production. As noted, early tar sands projects have an especially vital role to play that will probably warrant special consideration. In the event Arctic oil moves in later in large volumes, such oil may also achieve a preferred status, but the treatment might not be quite the same as for tar sands projects coming onstream earlier.

63. While the future environment looks to favor building up tar sands production rapidly, there are obviously practical limits on the number and scale of projects and on how fast they can be designed and constructed. Ongoing research into alternative techniques may take some years until the stage is reached when decisions can be made to move ahead on commercial ventures. Furthermore, there may be limits on the capacity of the engineering-construction industry to design and construct new facilities.

64. If a decision is made to move ahead on tar sands development, Alberta policy can only encourage further projects. Policy cannot push development at an unrealistic pace. Even if this were possible, the long-run results could be detrimental if it led to ill-conceived and hastily designed and constructed projects.

Diversification

65. Regardless of the pace of development, there would seem to be a real advantage to Alberta in encouraging diversification in tar sands efforts -- with regard to technology, numbers of participants, and in the mix of types of participants.

66. At this early stage, there is no way of knowing just what approach or approaches will turn out to be the most attractive methods of producing tar sands oil. Thus, over the long run, tar sands technology is likely to develop more rapidly and with better results if a wide range of alternatives is explored at the very beginning. Exploration of various approaches will almost inevitably lead to some efforts that are less successful than hoped for and perhaps even some failures. However, diverse ideas and approaches should also serve to turn up better technology than a more narrow focus.

67. To this end, Alberta policy should encourage a wide range of research and development efforts using differing technologies. Beyond that, as research leads to proposals for commercial projects, the Province should probably look with favor on projects which offer new and different approaches or techniques. The Province would obviously want to carefully review all proposals from the standpoint of their potential success. However, in the end, it must be the participants themselves who bear the responsibility and the risk of new approaches.

68. Diversification in the number of participants is also likely to serve the interests of Alberta. The number of participants will be limited by the number and scale of projects the Province is prepared to authorize. However, within limits, more participants could broaden the scope of approaches undertaken, add to the financial resources available for development, and widen the range of potential markets for tar sands oil. Domination of tar sands development by a few companies could have the opposite effects.

69. For the same reasons, diversification in the mix of participants would also look in the best interests of the Province. Alberta is likely to benefit from participation not only by major integrated companies, but also by independents and foreign companies as well.

Criteria for Participants

70. From the standpoint of the Province of Alberta, prospective participants in tar sands development would ideally possess technical competence, financial capability, and marketing ability to ensure disposition of production. In view of the importance of achieving a base load position for tar sands supplies, the third criterion could be particularly important. In reviewing applications for projects, the Province would want to consider very carefully what participants are prepared to provide in terms of contracting for disposition of output on a firm, long-term basis.

71. The major integrated companies would generally qualify on all of the above counts. Some have conducted or participated in tar sands research for some years now. All have wide experience in large-scale processing operations in oil refining and petrochemicals. Several have experience in mining operations, through diversification into coal. The majors are also obviously capable of providing substantial equity financing and have large borrowing power. Perhaps most important, the major integrated companies have their own integrated North American markets that could absorb large volumes of tar sands production. They are in a position -- and would have the incentive -- to make long-term commitments for offtake of tar sands oil.

72. The Canadian affiliates of the major integrated oil companies are strongly oriented to Canadian resource development and their exploration/development staffs are largely based in Alberta. But for Canada, these companies do represent foreign ownership. The Canadian Federal Government and the Province of Alberta may wish to consider foreign versus Canadian participation as one of the criteria for tar sands development. However, this is an issue on which we cannot really provide a judgment.

73. The Canadian independents have experience primarily in conventional oil and gas exploration. Some also have mining interests, both in coal and hard-rock minerals. But most have little, if any, expertise in processing, other than in natural gas plants. As noted earlier, lack of technical competence could be a major drawback to efforts by a Canadian independent -- or even a group of them -- to undertake a tar sands project on their own. But this would not really be an impediment to participation in a larger group where at least one or more of the other participants has the technical competence.

74. Much the same would be true for financing as well. Most Canadian independents would have difficulty in raising really large amounts of money on their own. But they could be in a position to finance smaller-scale interests, particularly where they are partners with major integrated companies who provide the technical competitive and perhaps guaranteed market outlets.

75. However, the independents need not necessarily be dependent on major-company participants for market outlets. Government policies in both the United States and Canada will be aimed at ensuring outlets for North American oil. Various U.S. refining companies who do not participate directly in tar sands development would probably be prepared to negotiate armslength deals for tar sands supplies on a long-term basis. Major integrated company participants would be primarily interested in supplying their own integrated markets, rather than selling tar sands oil to other refiners. But the third-party market could represent an important outlet for supplies of independent participants.

76. Thus, sales by independents could open up a range of competitive marketing that might otherwise be foreclosed if major companies are the only developers of the tar sands. This could serve to broaden the market for tar sands oil and, as noted, prices on third-party sales could aid in the valuation of tar sands oil for royalty purposes.

77. Foreign companies wishing to participate in tar sands development could also make an important contribution. Most of these companies have very considerable experience in large-scale processing, both in refining and petrochemicals. If they make a decision to participate in the tar sands, these companies would also have the financial capabilities, with some type of backing provided by their home governments.

78. As noted, foreign companies would probably look to sell their tar sands oil in North American markets. As with the independents, these companies lack a North American refining/marketing position. Thus, they would also have to look to offtake by major-company participants or armslength sales. However, these companies may also have opportunities for exchanging tar sands oil in North America for foreign oil elsewhere to meet their refining requirements abroad.

79. In sum, it appears likely that tar sands production will find market outlets up to the practical limits on development through the mid-1980's at least. It would look to be in the interest of the Province to get projects underway as rapidly as possible, in order to take advantage of the opportunities open to the tar sands over this period. In selecting projects, the Province should benefit over the long run from a policy aimed at a reasonable diversity of approaches and participants. Diversification of efforts should serve to advance the development of tar sands technology more rapidly and could broaden the basis of marketing of tar sands oil.

80. Alberta's huge tar sands resources offer a unique opportunity for the establishment of a major new industry, which could make a very valuable contribution both to North American oil requirements and to the Province itself. In setting a new long-range tar sands development policy, the Government of Alberta can play a very vital role in seeing that this opportunity is realized.

EMERGING NORTH AMERICAN OIL BALANCES:

CONSIDERATONS RELEVANT TO A TAR SANDS DEVELOPMENT POLICY

APPENDICES

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EMERGING NORTH AMERICAN OIL BALANCES:

CONSIDERATIONS RELEVANT TO A TAR SANDS DEVELOPMENT POLICY

APPENDICES

W. J. Levy Consultants Corp.
New York, N. Y.
February, 1973

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APPENDIX A

U.S. OIL REQUIREMENTS AND SUPPLIES

1. Future balances between oil demand and supply in the United States will clearly be a major factor in the determination of a policy for Alberta tar sands development. An emerging gap between U.S. oil requirements and indigenous crude oil production will provide the potential North American market for tar sands oil. The prices that bring U.S. oil requirements and supplies into balance over the years ahead will have an important bearing on the competitive value of tar sands oil and thus the economic attractiveness of tar sands production.

2. In this Appendix, we look first at trends in petroleum requirements in the United States over the next decade or so. These requirements are then set against anticipated levels of availability of crude oil and natural gas liquids from domestic sources, considering both established producing areas and prospective frontier areas. Finally, resulting projections of future U.S. oil import requirements are assessed.

3. There are many projections of future U.S. oil balances and it is not our purpose here to present yet another set of projections. Our approach is rather to review the range of responsible government and industry data, with particular emphasis on areas of uncertainty that may be important to the market prospects for tar sands oil.

4. Table A-1 summarizes a number of recent projections of U.S. oil demand and supply for the years 1980 and 1985. These include projections by --

Three oil companies (Arco, Shell, and Humble) and one group of oil companies (Syncrude applicants);

One industry advisory body to the U. S. Government (National Petroleum Council);

One U. S. oil-trade association (Independent Petroleum Association of America);

One bank (Chase Manhattan);

Three U. S. Government agencies (two by the Department of the Interior and one by the Office of Emergency Preparedness); and the

Alberta Energy Resources Conservation Board Staff.

Comparing Projections

5. Before considering the data themselves, a few preliminary observations on comparing projections of oil supply and demand are in order. Differences among projections can reflect various factors, including --

Definitions of what is meant by "demand" and "supply";

Assumptions underlying the projections;

Projection techniques employed; and

Possible biases on the part of parties making the projections.

6. Differences in definitions of terms used can pose difficulties in comparing various projections. For example, "product demand" may include export demand or may be demand in domestic markets only; product demand may refer to gross barrels of products demanded/consumed by final users

or may be "net" of barrels gained through refinery processing.* On the supply side, domestic production may be defined as crude oil only, or may also include natural gas liquids produced in gas-processing plants, projected production of synthetic oil from oil shale, etc. Unfortunately, projections are sometimes presented -- especially in public speeches -- without spelling out precisely what is meant by the terms supply and demand, making comparisons with other projections difficult. Where possible, we have attempted to put the projections included in our review on a comparable basis.

7. Differences in underlying assumptions can obviously lead to variations in projections of oil balances. Key assumptions relate to such developments as --

Technological change (e.g., in oil usage and in techniques of finding and producing oil);

Future levels of oil prices and the relative price of oil versus other fuels, which can affect both oil demand and supply;

Availability of oil and other energy sources to meet requirements;

Major changes in governmental policies;

Rates of economic growth, including the impact of swings in the business cycle; and

The impact of environmental improvement activities and restrictions on both energy consumption and energy availability.

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* In order to meet product requirements in the United States, which include a high percentage of lighter products such as gasoline, U.S. refiners have installed complex facilities to upgrade heavier fractions into lighter products. As a result of this upgrading, U.S. refineries turn out about 3 per cent more barrels of product (currently some 400,000 barrels daily) than barrels of crude oil and other materials used as inputs to refineries. This "processing gain" is often treated from a statistical standpoint as a deduction from product demand, rather than as a source of product supply -- including by the U.S. Bureau of Mines, the basic compiler of data on U.S. oil demand.

8. In some cases, all of the assumptions underlying projections of oil demand and supply are carefully spelled out; in other cases, they are not and can only be inferred indirectly. Sometimes the assumptions used in making projections represent a best judgment as to what will happen in the future. In other instances, assumptions are chosen simply to illustrate what might happen in the future under certain circumstances.* In still other cases, deliberately optimistic or pessimistic assumptions may be used in order to make a particular point.

9. Techniques for making projections of oil balances vary widely, from very mechanical extrapolations of past trends to very elaborate econometric approaches. However, in the final analysis, the specific tools used to make projections are probably less critical than the explicit or implicit assumptions underlying the projections.

10. One further general observation is in order with regard to projections of U. S. oil demand or requirements. It is clear that more recent projections of demand (i. e., made within the last two years or so, as included in our review) have tended to be significantly higher than earlier projections. This probably reflects several factors. First, many projections are based to some extent at least on an extrapolation of historical trends. Recent rates of growth in U. S. oil demand -- and in energy demand as a whole -- have been somewhat higher than previously and this fact alone has undoubtedly led to some "upgrading" of projections.

11. However, recent higher projections probably also reflect changes in basic analytic thinking about future U. S. oil demand. In recent years, oil has had to fill a larger than anticipated share of increases in U. S. energy requirements, owing to limited availability of other energy sources -- e. g., from lagging natural gas production, limitations on coal use owing to sulphur restrictions, and delays in nuclear power construction. With the outlook for limited supplies and/or high costs for incremental supplies of other energy sources, many recent projections assume that oil will continue to have to meet a larger part of increased energy requirements in the United States than anticipated earlier.

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* An example of this approach is provided by the National Petroleum Council's projections. In its analysis of future U. S. domestic oil supplies, "physical and economic factors were investigated under different sets of assumptions. Because there is considerable uncertainty regarding future conditions, no one case could be selected as most probable. Rather, the analysis focused on four cases, spanning what was judged to cover a probable range of future outcomes. Any one of the cases described in this report could occur under various conditions."

Demand

12. In 1972, U.S. domestic demand for oil (net of processing gains) averaged some 16.2 million barrels per day. For the future, the projections in Table A-1 show demand rising to --

> In 1980, a range of about 20 to 25 million barrels daily, or an annual rate of growth of 2 1/2 to 5 1/2 per cent between 1972 and 1980;* and
>
> In 1985, some 23 to 30 million barrels per day, or 2 3/4 to 5 per cent per annum between 1972 and 1985.*

In general, projections made by industry tend to be at the upper end of the ranges; those made by governments toward the lower end.

13. The considerable range in projections of U.S. oil demand -- some 5 million barrels daily in 1980 and 7 million in 1985 -- reflects a number of factors. Varying assumptions as to growth in total U.S. energy requirements account for some of the differences. These in turn depend upon anticipated rates of economic growth and assumptions about the relationship between rates of increase in energy consumption and rates of increase in economic activity, (the so-called "energy coefficient"). It should be noted, however, that none of the "standard" projections apparently assume major efforts at energy conservation in the United States over this period (of which more below).**

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* These ranges exclude (i) the projections of the Office of Emergency Preparedness (OEP), which assume that the United States deliberately adopts a variety of measures designed to conserve energy (of which more later) and (ii) the NPC's Case 1, which is described as "difficult to attain."

** For example, the Chase Manhattan Bank projection of demand, one of the highest, is based on the premise that "considering all the factors involved, the growth of per capita energy use is likely to accelerate in the year ahead. And, by 1985, it is expected to be nearly two-thirds greater than in 1970."

Substitution of Oil For Gas

14. Probably the most important factor in explaining the range of U. S. demand projections are differing assumptions as to the role of oil versus other energy sources in meeting future energy needs. The higher projections of oil demand tend to assume that oil will meet a relatively large share of increased total energy demands. In particular, oil is seen as meeting a substantial energy market that would have been met by gas, absent limited availability and very much higher prices for incremental gas supplies.*

15. Just how much substitution there will be of oil for gas in the U. S. energy economy will depend primarily on the relative prices of the two energy sources over the years ahead and future U. S. energy/import policies. These developments are obviously difficult to predict.

16. Since imported energy will provide the bulk of incremental supplies to meet U. S. energy requirements it is the delivered cost of foreign oil and gas that will be the decisive factor in the competitive interplay between the two fuels. Present price relationships would favor offshore oil as against offshore gas in liquefied form or gas manufactured from offshore liquid feedstocks. Looking ahead, foreign crude oil prices are inevitably headed upward, with the pressure coming from escalating "take" by producing governments rather than a physical shortage of supplies in world markets. However, foreign LNG and SNG feedstock prices are likely to escalate at least as rapidly as foreign crude oil prices and perhaps even more rapidly.

17. In general, there are much more limited sources of supply for LNG and SNG feedstocks than for crude oil and supply arrangements tend to be more uniquely tied to individual sources. As a result, competitive forces in LNG and SNG feedstock markets may be weaker and opportunities for producing governments to increase their "take" may be greater. Thus, it is unlikely that future escalation in foreign crude oil versus LNG and SNG feedstock prices would work to tip the balance strongly in favor of gas in U. S. markets and could well work in favor

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* Again, Chase Manhattan says "of over-all growth of the nation's energy needs between 1970 and 1985, oil alone is expected to accommodate half. To a significant degree, the exceptionally strong increase in the demand for oil reflects the rapidly developing shortage of natural gas ... the demand for oil in 1985 will be 15 per cent larger than might normally be expected [absent shortages of gas]."

of foreign crude oil. In sum, while future oil/gas price relationships are difficult to predict, the indications are that fuel oil based on delivered crude costs (or even direct burning of low-sulphur crude oil) could be competitive with gas in under-the-boiler uses in various U.S. markets.

18. It is clear that the United States will have to increase its energy imports substantially. To the extent energy policy requires authorization of energy imports from offshore, the availability and flexibility of crude oil supplies would look to make crude oil also preferable from a security standpoint to LNG or even SNG supplies based on imported feedstocks. The potential hazards with respect to security of supply appear to be considerably greater for imports of either LNG or SNG feedstocks than for imports of crude oil. As noted, potential sources of supply for LNG or SNG feedstocks are much more limited than for crude oil importation. In the case of crude oil, processing oil facilities are located in the United States, as against offshore processing locations for LNG (liquefaction plants) and SNG feedstocks (refineries). Furthermore, transportation of LNG and feedstocks for SNG involves more specialized vessels, which are generally in limited availability. LNG requires specially constructed tankers for carrying gas in liquid form at extremely low temperatures; LPG, pressurized tankers; and crude oil fractions such as naphtha, limited-size clean tankers. This is in contrast to the very large and flexible fleet of tankers available to carry crude oil.

19. Even if the economic outlook and security considerations set out above are essentially correct, it is still difficult to predict what future U.S. energy and import policies will be. But the basic realities that are likely to bear importantly on U.S. policies over the long run would point in the direction of allowing oil to meet substantial energy needs that might otherwise be met by gas. And this would point in the direction of higher rather than lower levels of future U.S. oil demand.

Energy Conservation

20. In the face of potential energy shortages in the United States, some consideration has begun to be given to possibilities for instituting various measures which would either improve on the efficiency with which energy is

consumed or minimize the consumption of energy.* A study by the U.S. Office of Emergency Preparedness (OEP) has identified areas of consumption which offer possibilities for significant reduction in the rate of growth of overall energy use and has estimated the potential impact of energy-conservation measures on the demand for oil and other energy supplies. Table A-1 shows maximum estimated savings in oil consumption should all the suggested conservation measures be implemented in each of three classifications based on the time period required for implementation. By 1985, the OEP estimates that 1.8 million barrels daily could be saved via short-term measures (i.e., those which could be implemented in the period 1972-1975), another 2.9 million barrels per day by mid-term measures (i.e., 1976-1980), and another 1.6 million barrels daily by long-term measures (i.e., beyond 1980).

21. Thus, OEP estimates would suggest that the immediate actions towards a maximum effort at energy conservation might result in a significant reduction in U.S. oil demand. There is little doubt that certain energy-conservation measures will probably be adopted -- particularly in a society increasingly concerned with ecology and environmental protection.** However, it is unlikely that anything approaching a maximum effort will be made any time soon. The OEP study stresses in evaluating its results that

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* The OEP divides conservation measures into two categories identified as "belt tightening" and "leak plugging." As set out by the OEP, "'belt tightening' is defined as those measures which would reduce energy output at fixed efficiency levels. 'Belt tightening' can take the form of long-term efforts to encourage reduced consumption or emergency measures to prevent or mitigate brownouts and blackouts... 'Leak plugging,' is defined as those measures which would retain performance while increasing efficiency. Thus, 'leak plugging' would rely on applications of extant technology, such as improved insultation in buildings, and other measures which would improve the efficiency of energy use in the short and mid-term. Efficiency improvements in the longer term would require new technological developments and/or larger scale application of available technology."

** It is important to note that concern with ecology and environmental protection also works in the direction of higher energy use, since many measures designed to protect the environment themselves require substantial volumes of energy. For example, use of lead-free gasoline to improve the quality of the air lowers the efficiency of automobile engines (i.e., results in fewer miles per gallon) and thus works to increase gasoline demand. Efforts to clean up air and water pollution by industry also require added energy, as well as the restoration of the damage to the earth brought about by strip mining for coal and oil shale.

"no in-depth analysis of feasibility or consumer acceptance has been taken... many of the conservation measures suggested may not be acceptable." The most significant energy conservation measures are ones which would involve major changes in energy utilization and/or very large investment outlays by consumers, industry, or government --

> The installation of improved insulation in both new and old homes and the use of more efficient air conditioners;
>
> A shift in intercity freight from trucks to rail; intercity passengers from air to rail and bus, and urban passengers from automobiles to motorized mass transit; and
>
> The introduction of more efficient industrial processes and equipment.

Many of these measures would probably require restrictive regulations and/or tax incentives (either credits or penalties) to implement and it is not at all clear that the U.S. public will accept or impel very drastic steps in these directions -- particularly if it is felt that adequate energy supplies are likely to be available at prices that while significantly higher than at present are still not unreasonable.*

22. As noted earlier, most projections assume that measures aimed at conservation of energy will have only a comparatively minor impact on oil consumption, particularly through 1980. However, the further one looks into the future, the greater the chances are that there may be increased rationalization and conservation in the use of energy. Furthermore, the more rapidly demand for energy grows relative to availability, the higher energy prices are likely to be and the more prices themselves will act as an energy conservation measure.

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* The OEP study has been met with considerable criticism. For example, the Vice President for Public Affairs of The Conference Board (a non-profit business research organization) called the concepts in the study a "repressive mode of societal organization wholly lacking in the very things we mean by quality of life" and concluded that "what such an array of regulations, punitive and incentive taxes and other persuasion tactics would yield goes far beyond conservation of energy." Subsequently, a spokesman for the OEP indicated that the study was intended only as "food for thought" and not a "portent of national policy in the near future."

Supply

23. Against the range of rising U.S. oil requirements set out above, projections of U.S. oil production show relatively modest growth at best. In 1972, total U.S. production averaged some 11.2 million barrels daily (of which 9.5 million barrels per day was crude oil and lease condensate and 1.7 million barrels daily was natural gas liquids. The projections in Table A-1 show total crude and NGL production of --

> In 1980, a range of about 9 to 14 million barrels per day, or from a decline of 2 million barrels daily to an increase of 3 million from the level of 1972; and
>
> In 1985, a range of about 10 to 15 million barrels per day,* or from a decline of 1 million barrels daily to an increase of 4 million from 1972.

24. For purposes of analysis, future levels of U.S. oil production can be conceived of as consisting of four basic components --

> Production from presently known reserves in established producing areas;
>
> Production from presently known reserves not now being produced (essentially on the North Slope of Alaska);
>
> Production from reserves yet to be found; and
>
> Production of synthetic liquids from oil shale and coal.

25. In general, projections of U.S. oil production indicate separately the volumes of production assumed from the North Slope and from synthetics. Assumptions as to North Slope production are reasonably comparable in most projections -- about 2.0 million barrels daily in 1980 (approximately the capacity of the planned Alyeska line to south Alaska), rising to some 2 1/2-3 million barrels per day in 1985. Projections of synthetic oil production

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* Excluding the extreme NPC Case I projection (17 million barrels per day).

(largely from western oil shale) vary somewhat, but the volumes projected are relatively small in the overall production picture -- i.e., generally minimal volumes by 1980 and not exceeding 500,000 barrels daily or so by 1985.

26. Thus, the largest part of differences among projections of U.S. oil production is accounted for by conventional oil production outside the North Slope. Projections of U.S. production are not usually broken down between what is expected from known or proven reserves versus reserves to be discovered in the future. However, assumptions as to production from presently known reserves -- either explicit or implicit -- are not likely to differ very markedly among projections. Assumptions as to the percentage of oil reserves in place that will be economically recoverable may differ somewhat, depending upon what is assumed about future technology and prices. But rates of decline in production from established reservoirs are reasonably well known.

27. The major differences among projections of U.S. production are probably owing to differences in assumptions as to production from reserves that have yet to be discovered. This is obviously an area of considerable uncertainty. Future reserves will be related to --

> Levels of exploratory activity, which will depend in turn upon such factors as future prices, import policy, incentives under tax regulations, and availability of prospective acreage for leasing; and
>
> Returns to the exploratory effort, which will be a function of ultimate reserves in the ground and the productivity of the industry in finding reserves.

28. Rates of production from future additions to reserves will reflect various factors, including --

> The balance between domestic and foreign supplies in meeting domestic requirements under import policy;
>
> State prorationing, if any; and
>
> Environmental delays in moving new reserves into production (e.g., as has been the case for Prudhoe Bay).

29. Given the number of factors and the uncertain relationships involved, it is not surprising that projections of U.S. oil production should vary considerably. In general, higher projections tend to assume a relatively favorable economic and political environment for domestic resource development, together with reasonably good results from exploratory efforts. Lower projections tend to assume a less favorable climate -- e.g., limited increases in U.S. crude prices, continued environmental delays (particularly in leasing), uncertainties under U.S. import policy, etc. -- and less attractive returns to exploration.

Net Imports

30. Differences between anticipated U.S. product demand and domestic production provide projections of future U.S. net oil import requirements. In view of the range of projections of demand and supply, it is not surprising that projections of net import requirements also vary considerably. In 1972, total U.S. oil imports -- including both crude oil and petroleum products (largely residual fuel oil) -- came to some 4.7 million barrels daily. Projected volumes of net imports (excluding the NPC extreme Cases I and IV) range from --

> In 1980, 7-1/2 to 13 million barrels per day, or an increase of around 3 to 8 million barrels daily over 1972;
>
> In 1985, 8.7 to 19 million barrels per day, or an increase of some 4 to 14 million barrels daily over 1972.

31. Under any of these projections, the dependence of the United States on imported oil would increase sharply. In 1972, total U.S. oil imports represented some 29 per cent of domestic product demand. The percentage of demand met by imports in 1980-1985 is projected to increase to a minimum of 37-38 per cent, up to a maximum of 65-66 per cent.

32. A key factor in determining the levels of U.S. oil imports in the 1980-1985 period will clearly be U.S. energy/import policy. The highest projections of U.S. oil imports above would probably be realized only in the event that the United States fails to take really significant steps to deal with

its energy problems and present trends continued essentially uninterrupted.* In view of the current high degree of concern with the so-called "energy crisis," this would seem to be a fairly unlikely course of events. On the other hand, the lowest projected levels of U.S. oil imports above could probably be achieved only through the early adoption of vigorous policies to spur development of domestic resources of all kinds -- conventional oil and gas, coal gasification and liquefaction, oil shale, and nuclear power. While this is also a possibility, the chances of it happening probably also must be rated relatively low.

33. It is quite unlikely that high levels of demand will coincide with low levels of domestic supply. In these circumstances, the economic interaction of demand and supply would work toward higher prices and this in turn would tend to narrow the import gap from both the demand and supply side. Insofar as public policy may bear upon oil balances, a sharply widening gap between demand and availability of domestic supplies is also likely to bring about various measures aimed at mitigating reliance upon imports. Thus, the chances are that imports will fall somewhere in between the low and high of the ranges set out above.

34. Over the period through 1980 or so, U.S. policies directed at development of indigenous resources and/or energy conservation are likely only to have a moderate impact on import volumes. Come what may, it looks like the level of U.S. oil imports by 1980 will be upwards of 7 1/2 million barrels daily. With substantially higher levels of imports, the United States will inevitably have a greater concern over the origin of its imported oil supplies. From the standpoint of security, imports from Canada will be a preferred source of supply.

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* The high of the range of oil imports for 1985 -- 19 million barrels daily -- just about matches the NPC's Case IV, which assumes that disputes over environmental issues continue to constrain growth in output of all fuels, government policies continue to be inhibiting, and oil and gas exploratory success does not improve over recent results.

35. Inevitably rising import volumes through the balance of the 1970's will give heightened concern to security of U.S. oil supplies over the longer run. Policies adopted during the 1970's could have a considerable impact by the 1980's. The United States is likely to look to all potential sources of new large-scale North American oil supplies. Intensified efforts to find conventional crude oil resources could provide substantial new volumes of production, although the degree of success that may be achieved is uncertain. Synthetic oil from domestic coal and oil shale could also be significant sources of supply. But there are problems of developing the economics and technology of synthetic oil production which will take some time to work out. And both coal and shale pose very significant environmental difficulties -- which will have to be overcome. The Alberta tar sands are a third major source of new North American oil supplies. As with U.S. coal and oil shale, known tar sands resources are large. In contrast, however, a significant start has already been made to develop tar sands production on a commercial basis. Thus, the prospects at least are probably more favorable for the establishment of larger volumes of tar sands production at an earlier date and with somewhat less uncertainty than for U.S. synthetics.

TABLE A-1

PROJECTIONS OF U.S. OIL DEMAND/SUPPLY BALANCES, 1980 AND 1985

(Millions of Barrels Daily)

	1980			1985		
	Product Demand	Domestic Production	Net Import Requirements	Product Demand	Domestic Production	Net Import Requirements
Chase Manhattan Bank (June, 1972)				29.5[a]	14.3	15.2
Atlantic Richfield (1972)	25.0	13.0	12.0			
Shell (May, 1972)	24.5	11.5	13.0	29.0	10.0	19.0
Syncrude Applicants (Dec., 1971)	24.0	12.9	11.1			
Humble (May, 1972)				27.7	10.7	17.0
Laird-Dept. of Interior (May, 1971)				27.0	15.0	12.0
National Petroleum Council (Dec., 1972)[b]						
Case IV	25.3	8.9	16.4	29.7	10.5	19.2
Case III	22.3	11.7	10.6	25.8	12.3	13.5
Case II	20.5	13.0	7.5	23.1	14.4	8.7
Case I	19.6	13.8	5.8	20.5	17.0	3.6
ERCB Staff (Dec., 1971)	21.8	13.5	8.3			
Dept. of Interior (Dec., 1971)	21.4	13.9	7.5	26.2	14.6	11.6
Independent Petroleum Association of America				26.0		
Office of Emergency Preparedness (Oct., 1972):[c]						
No Energy Conservation Measures	20.8			25.0		
With Short-Term Measures	19.4			23.2		
With Short and Mid-Term Measures	16.8			20.3		
With Short, Mid, and Long-Term Measures	16.8			18.7		

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[a] Total product demand of 30.2 MB/D net of processing gain of 0.7 MB/D.

[b] NPC oil demand projections based on i) electricity fuel mix "base case" and ii) intermediate projection of total energy demand. Energy supply cases are based on: Case I -- assumes maximum effort to develop all domestic fuel sources; Case IV -- assumes that disputes over environmental issues continue to constrain growth in output of all fuels, government policies continue to be inhibiting, and oil and gas exploratory success does not improve over recent results; Cases II and III -- intermediate cases.

[c] OEP estimates are "idealized projections of petroleum consumption based on suggested conservation measures." Their energy conservation measures are classified by the time period which would be required for implementation -- short-term (1972-1975), mid-term (1976-1980), and long-term (beyond 1980).

APPENDIX B

CANADIAN OIL UNDER U.S. OIL IMPORT POLICY

1. Appendix B deals with the status of Canadian oil under U.S. oil import policy and the role of exports in the build-up of Canadian oil production over the past two decades.

2. Since the mid-1950's, the volumes of foreign oil that could enter U.S. markets have been subject to some form of restriction. U.S. oil import policy stems from findings of a specially convened Cabinet Committee in 1954: (i) that the national security requires a healthy and vigorous domestic producing industry, and (ii) that, in turn, requires imports to be limited to ratios then obtaining between foreign and domestic oil. Since then, U.S. oil import policy has evolved in many diverse respects. Importing companies were first called upon to hold to their own import schedules in line with industry guidelines; then voluntary quotas were established; in course, the mandatory oil import quota program was established in March, 1959. The overall ceiling on foreign oil has been variously related to domestic production or domestic consumption, actual or projected, and the ratios have varied. Imports from time to time have been restricted by, or have been exempted, with respect to country of origin, destination within the United States, and the nature of the oil.

3. Within the U.S. oil import program, Canadian oil has never been accorded the same status as domestic oil, but it has been accorded preference among foreign sources of supply. Just how Canadian oil was treated over the years tended to reflect the experience of the time -- depending on whether it looked to impinge on domestic production as surplus domestic capacity weighed heavily, or whether it looked to be an essential supplement to domestic production, serving to offset short-term unavailability of other foreign oil or helping avoid long-term dependence on less secure foreign oil sources.

4. From June, 1959 until March, 1970, imports from Canada entering "overland" into the United States did not require a quota and thus did not have to compete with lower-cost offshore crude for acceptance under a U.S. refiner's

quota. (See Table B-1 for a Chronology of United States Oil Import Policy with Regard to Canadian Oil, 1955 to Date.) However, in order that the rate of build-up in Canadian imports would not impinge unduly on domestic production, projected levels of Canadian imports were charged against overall U.S. import ceilings, before arriving at the volume of quotas that would be allocated for offshore imports. On the other hand, there were continuing consultations between the U.S. and Canadian Governments to agree on acceptable levels of Canadian imports, so that the rate of increase in Canadian imports should not impinge unduly on resulting offshore quota volume to the extent that access of other Western Hemisphere (notably Venezuelan) oil to U.S. markets was impaired. Direct quota limitations on Canadian oil imported into Districts I-IV (East-of-the-Rockies) were first imposed in March of 1970, when a sharp uptrend in imports from Canada threatened to impair "the management of the present import control program and the early development of future oil import policies."

5. Over the years 1960 to 1972, Canadian oil clearly benefited from its preferred status under U.S. oil import controls. Total U.S. imports of crude and unfinished oils increased from 1.0 million barrels daily in 1960 to 2.3 million barrels per day in 1972 -- an overall increase of some 1.3 million barrels daily. (See Tables B-2 and B-3.) Over the same period, crude and unfinished oils imports from Canada increased from 115,000 barrels per day to 800,000 barrels daily -- a gain of almost 700,000 barrels daily. Thus, increased imports from Canada accounted for two-fifths of the total rise in U.S. crude imports over the past decade or so.

6. For Canada, increased exports to the United States accounted for the largest part of the total rise in production. Between 1960 and 1972, Canadian production of crude oil and crude oil equivalents increased rapidly from 530,000 barrels per day to 1,700,000 barrels daily, a gain of 1,170,000 barrels per day -- of which 835,000 barrels daily represented increased exports to the United States and 330,000 barrels per day increased demand by Western Canadian refineries. (See Table B-4.) In course, exports rose from around 20 per cent of Canadian production in 1960 to some 56 per cent by 1972.

7. But despite the relatively rapid build-up in production, market outlets and thus production of Canadian crude did not keep pace with the development of Western Canada's crude resource base until recent years -- the crude reserve-to-production ratio rising from 17 years in 1956 to 25 years in 1966 (34 years in Alberta). Since 1966, however, production has grown faster than reserves, with the ratio of reserves-to-production declining to an estimated 13-14 years in 1972 (17-18 years in Alberta).

TABLE B-1

CHRONOLOGY OF UNITED STATES OIL IMPORT POLICY WITH REGARD TO CANADIAN OIL, 1955 TO DATE

Pre-Voluntary Program (April 1955-June 1956)

Office of Defense Mobilization (ODM) calls upon individual oil importing companies to restrain their receipts of foreign oil in 1955-56. Imports of Canadian oil excepted, although it is indicated by ODM that Canadian and other excepted imports are not expected to increase very significantly and would be watched carefully.

Voluntary Oil Import Program (July 1956-March 1959)

Oil import controls imposed on a voluntary basis, with quotas allocated to companies. Canadian oil not exempted from restrictions.

Mandatory Oil Import Program (March 10, 1959 to Date)

March 10, 1959. Oil import controls made mandatory. In establishing program, President recognizes joint interest in hemisphere defense and announces effort to coordinate oil problems with Canada. But initially, Canadian crude subject to quota allocations and treated on same basis as imports from other foreign areas, as under Voluntary Program. (Exceptions granted to Upper Midwest refiners unable to obtain supplies of domestic crude by ordinary and continuous means such as barges, pipelines or tankers.)

June 1, 1959. Exemption from ceilings and allocations of oil transported into "the United States by pipeline, motor carrier or rail from the country of production." Refinery throughput of oil from exempt "overland" sources excluded from base period refinery inputs for purposes of calculating company quota allocations for offshore imports.

TABLE B-1 (Cont'd)

January 1, 1960. Estimated exempt imports from Canada into District V to be deducted from forecast of supply deficiency to arrive at total allocable quota for offshore imports in District V.

January 1, 1963. Imports from Canada to be included within ceiling on total permissible imports into Districts I-IV and estimated imports from Canada to be deducted from Districts I-IV ceiling in arriving at volume of allocable quotas for offshore imports.

1963-1967. Although exempted from formal controls, a system of informal restraint develops. The U.S. Assistant Secretary of the Interior was quoted in 1966, "...through cooperative efforts ...a degree of stability has been obtained without any kind of formal controls." In early 1968, the Resources Minister told the Canadian House of Commons that "we do not want to have export controls and consequently we have to accept certain regulations in connection with [oil matters]."

September 25, 1967. In connection with authorization of border crossing for Interprovincial Pipe Line loop via Chicago, formal arrangements between United States and Canadian Governments worked out limiting the flow of exempt Canadian refinery feedstocks into Districts I-IV. In a letter dated September 25, 1967 from the Canadian Ambassador to the United States Secretary of State, the Canadian Government endorsed: a ceiling on exports of 280,000 barrels daily in 1968, with growth during 1969-1971 not to exceed 26,000 barrels per day per annum; no sales into the then untapped Chicago area prior to 1970; avoidance of disruption of United States markets and no displacement of local production of crude oil in those states served by Canadian exports. These arrangements were to be ensured by the Canadian Government, short of imposing formal export controls.

March 10, 1970. President imposes volumetric restrictions on the importation of Canadian oil into Districts I-IV as a means of interim control during the transition to an alternative United States-Canadian energy policy. Quota ceilings established and quotas allocated to companies.

October 16, 1970. Natural gas liquids derived from Canadian natural gas and imports of crude from Canada to be topped for use as burner fuel exempted from volumetric restrictions on imports of Canadian oil in Districts I-IV.

TABLE B-2

UNITED STATES DISTRICTS I-IV IMPORTS OF CRUDE AND UNFINISHED OILS UNDER MANDATORY IMPORT PROGRAM -- CANADIAN VERSUS OFFSHORE, 1960-1972

	Total Imports of Crude and Unfinished Oils	Canadian	Offshore[a]
1972	1,660	670	990
1971	1,269	522	747
1970	1,055	448	607
1969	1,117	352	765
1968	1,042	302	740
1967	849	232	617
1966	941	191	750
1965	904	158	746
1964	878	141	737
1963	860	124	736
1962	854	111	743
1961	801	94	707
1960	776	64	712

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[a] Includes small volumes of overland imports from Mexico.

Source: 1960-1971, United States Oil Imports Administration; 1972, estimated.

TABLE B-3

UNITED STATES DISTRICT V IMPORTS OF CRUDE AND UNFINISHED OILS UNDER MANDATORY IMPORT PROGRAM -- CANADIAN VERSUS OFFSHORE, 1960-1972

	Total Imports of Crude and Unfinished Oils	Canadian	Offshore
1972	625	275	350
1971	551	210	341
1970	405	222	183
1969	421	210	211
1968	350	167	183
1967	392	190	202
1966	394	166	228
1965	433	144	289
1964	415	142	273
1963	360	130	230
1962	376	128	248
1961	322	92	230
1960	292	50	242

Source: United States Oil Imports Administration.

TABLE B-4

DISPOSITION OF CANADIAN PRODUCTION OF CRUDE OIL AND EQUIVALENTS, 1956-1972

(Thousands of Barrels Daily)

		Receipts of Canadian Refiners				Exports		
	Production[a]	Total	British Columbia	Prairie Provinces[b]	Ontario	Total	U.S. District V	U.S. Districts I-IV
1972	1,695	750	130	230	390	945	275	670
1971	1,475	730	127	225	378	745	210	535
1970	1,382	700	118	215	367	680	220	460
1969	1,229	663	106	216	341	548	207	341
1968	1,125	645	112	206	327	457	163	294
1967	1,044	615	102	203	310	414	186	228
1966	956	603	94	197	311	349	162	187
1965	876	571	81	191	300	296	143	153
1964	819	548	82	183	283	278	141	137
1963	768	509	72	177	260	249	127	122
1962	716	481	77	170	234	234	124	110
1961	628	451	69	155	227	183	91	92
1960	532	418	68	153	197	112	49	63
1959	513	430	66	166	198	92	33	59
1958	457	375	58	152	165	81	24	57
1957	501	354	62	155	137	151	93	58
1956	472	343	59	149	134	116	49	67

Notes: (i) All data include crude oil and crude-oil equivalents (condensate, pentanes plus, and synthetic crude oil produced from Tar Sands).

(ii) Differences between production and sum of receipts of Canadian refiners and exports reflect stock changes.

a Includes Tar Sands production of 1 TB/D in 1967, 16 TB/D in 1968, 28 TB/D in 1969, 33 TB/D in 1970, 43 TB/D in 1971 and TB/D in 1972.

b Alberta, Saskatchewan, and Manitoba plus Northwest Territories and Yukon.

Sources: Canadian Petroleum Association, Oilweek, Dominion Bureau of Statistics, and United States Oil Import Administration.

APPENDIX C

CANADIAN AND U.S. CRUDE OIL PRICES

1. Appendix C deals with Canadian and U.S. crude oil prices -- the history of Canadian wellhead prices from 1956 to date and current relationships among delivered prices of U.S. and Canadian crudes in major U.S. refining centers.

2. Table C-1 shows a chronology of the wellhead price of a representative Canadian crude -- Redwater -- and the announced or apparent reasons for price changes.* In early years, Canadian crudes were generally priced on the basis of parity with competing crude in perimeter markets. From the time that Canadian crude began moving into Ontario until 1959, Canadian crude was priced to equalize with U.S. crude at Sarnia -- i.e., Canadian wellhead prices represented a netback from the delivered price of U.S. crude at Sarnia. Thus, changes in the price of Redwater crude in 1957 and 1958 shown in Table C-1 reflect changes in factors which affected parity at Sarnia --

> In January 1957, there was a substantial increase in price, largely as the result of the hike in U.S. crude prices (in particular, the price of Illinois Basin crude) occasioned by the Suez Crisis.**
>
> In August 1957, the Redwater price was decreased slightly to adjust for the rising value of the Canadian dollar relative to the U.S. dollar (and thus the increasing price of Redwater crude compared with U.S. crude); and

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* The price developments and reasons for price changes in Table C-1 are typical of Alberta crudes. Price adjustments for Saskatchewan crudes have tended to be somewhat more independent. Saskatchewan crudes are not prorated and the competitive basis for pricing of Saskatchewan crudes has the effect of ensuring production virtually at capacity.

** The increase of 18 cents per barrel was somewhat less than the 25 cents increase in U.S. crude prices. The smaller increase in Canadian crude prices was owing to the fact that the relative strength of the Canadian dollar had risen since the last change in the price of Redwater crude in February 1955.

In May 1958, the price of Redwater crude was further cut, reflecting a decline in the Illinois Basin crude price.*

3. In March of 1959, Canadian crude prices were reduced substantially. The basic reason for the reduction was to make Canadian crude competitive in the new perimeter markets to which it was then moving -- beyond Sarnia to Toronto, where products refined from Canadian crude moved into competition with products refined from foreign crude in Montreal in the watershed between the two refining centers; and across the border into the United States, reaching Detroit and even Toledo. At the same time, in consideration of the substantial volumes of crude that would be moving over the long haul, Interprovincial Pipe Line tariffs were reduced, with the largest reductions in tariffs over the greatest distances.

4. Canadian crude prices were then increased in 1961 and 1962, reflecting a further decline in Interprovincial tariffs in 1960 and devaluation in the Canadian dollar in the Fall of 1961 and the Spring of 1962. In the years 1963-1969, Canadian crude price levels remained unchanged -- despite general increases in U. S. crude prices of 10 cents in 1966-67 and 20 cents in 1969. Over this period, Canadian crude developed a very considerable margin of competitive advantage over U. S. crudes in northern U. S. refining centers.

5. However, in mid-December 1970, Canadian crude prices were increased by 25 cents per barrel, paralleling the increase in U. S. prices in November of that year. In April 1972, prices were increased by 1 cent per barrel, reflecting a further small decline in Interprovincial tariffs. Then, in November 1972, Canadian crude prices were increased by another 10 cents per barrel to bring prices "more in line with competitive crudes in key markets."

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* The decline of 7 cents per barrel, however, was larger than the 5 cents per barrel reduction in the Illinois Basin price, the larger decline (as the smaller increase in January 1957) reflecting the continuing appreciation of the Canadian dollar over this period.

6. Two months later, in January 1973, Canadian crude prices were raised once again by a further 20 cents per barrel. This latest increase was attributed to three factors --

Increased costs of exploration and production experienced by Canadian crude oil producers over the last decade;

Higher taxes imposed by the Alberta Government as of January 1, 1973; and

Parallel price increases in the major producing areas outside North America.

7. Tables C-2 through C-5 deal with the current competitive position of Canadian crude in four U.S. refining centers. Each table shows the delivered cost of Alberta Redwater crude versus the delivered cost of reasonably comparable U.S. domestic crudes available in the area, as of January 1973.*

8. Table C-2 shows the approximate delivered costs of domestic and Canadian crudes in the Chicago refining center. On the basis of current wellhead prices and pipeline tariffs (including gathering charges), West Texas and Southern Louisiana crudes would lay into Chicago at a little over $3.90 per barrel. West Texas crudes carry a somewhat lower wellhead price than Louisiana crudes ($3.58 versus $3.65), but higher pipeline transportation charges ($.33 versus $.27)** to the Chicago market. Against this, on the basis of current postings, Interprovincial Pipe Line tariffs, and U.S. import duty, comparable Canadian crude would deliver into Chicago at just under $3.80 per barrel, or a competitive advantage over domestic crude of approximately 10-15 cents per barrel.

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* No account is taken of quality differentials among crudes -- other than gravity (all crudes taken at 35° API) and sulphur content (all crudes are reasonably low in sulphur -- i.e., less than 0.6 per cent sulphur by weight). Minor items such as pipeline allowance, loss, and insurance are omitted. Conversion from Canadian to U.S. currency taken at parity. All delivered Canadian prices include U.S. import duty of 10.5 cents per barrel.

** There are a number of alternative pipeline routes by which Southwest crudes can reach the Midwest, with varying costs. The pipeline charges shown above represent the lowest combination of gathering and trunkline tariff rates filed with the U.S. Interstate Commerce Commission.

9. Table C-3 shows delivered crude costs at Toledo. Domestic crudes would carry a delivered cost of just under $4.00 per barrel in Toledo. Against this, Redwater would lay in at just under $3.90 including duty, for an advantage of some 10 cents per barrel, so that Canadian crude's comparative advantage in Toledo is about on a par with that in Chicago.

10. Table C-4 shows competitive crude price relationships in the Twin Cities (Minneapolis-St. Paul) area. In this refining center, Canadian crude is fairly close to parity with North Dakota crude.

11. The final table of Appendix C, Table C-5, shows delivered crude costs in Puget Sound. In this area, Canadian crude has a somewhat larger advantage over "lower 48" crude than East-of-the-Rockies, with Redwater laying in at an average of around 25 cents below California crude delivered by tanker. On the basis of crude postings, Canadian crude lays in somewhat above Alaskan Cook Inlet crude in the Puget Sound area.

12. In the context of emerging U.S. crude oil balances, near-term demand for Canadian crude in U.S. markets could be largely independent of competitive price relationships. However, depending upon the level of offshore crude imports and the resulting re-distribution of U.S. crudes, Canadian crude prices could affect the "watershed" served by Canadian crude. This raises questions as to the pricing of Canadian crude in both markets to which Canadian crude moves -- Canadian domestic and export.

TABLE C-1

CHRONOLOGY OF WELLHEAD PRICE OF REDWATER CRUDE AND REASONS FOR PRICE CHANGES, 1957 TO DATE

(Canadian Dollars per Barrel)

	Wellhead Price	Reason for Change[a]
Price, December 31, 1956	$2.49	
Dates of Changes:		
January 16, 1957	2.67	Equalization at Sarnia -- increase in Illinois Basin crude price -- and currency adjustment.
August 30, 1957	2.63	Currency adjustment.
May 5, 1958	2.56	Equalization at Sarnia -- decrease in Illinois Basin crude price -- and currency adjustment.
March 24, 1959	2.42	Shift in the basis of pricing from equalization with U.S. crude at Sarnia, so as to take account of competitive relationships with foreign oil in perimeter market
September 11, 1961	2.52	Reduction in Interprovincial Pip Line tariff (Nov. 1960) and currency adjustment.
May 10, 1962	2.62	Currency adjustment.
July 1, 1968	2.67	Point of delivery shifted from wellhead to field gate.
December 15, 1970	2.92	In line with increase in U.S. crude prices.
April 1, 1972	2.93	Reduction in Interprovincial Pipe Line tariff.

TABLE C-1 (Cont'd)

CHRONOLOGY OF WELLHEAD PRICE OF REDWATER CRUDE AND REASONS FOR PRICE CHANGES, 1957 TO DATE

(Canadian Dollars per Barrel)

Dates of Changes:	Wellhead Price	Reason for Change[a]
November 6, 1972	$3.03	To bring Canadian crude prices "more in line with competitive crude prices in key markets."
January 9, 1973	3.23	To reflect increased costs of Canadian exploration and production, higher taxes imposed by the Alberta Government, and increases in crude oil prices in the major producing areas outside North America.

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[a] In some instances the reasons for change have been publicly announced; in others, the reasons have been inferred from the context of current developments.

TABLE C-2

APPROXIMATE DELIVERED CRUDE OIL COSTS, JANUARY 1973 -- CHICAGO

(Dollars per Barrel)

	Canadian Redwater	Southern Louisiana	West Texas Sweet
Wellhead Price	$3.23[a]	$3.65	$3.58
Gathering	...	.05	.05
Pipeline Tariff	.44[b]	.22	.28
U.S. Import Duty	.105	...	...
	$3.78	$3.92	$3.91

Notes: (i) Approximate delivered crude costs based on published posted wellhead prices and ICC tariff rates. Minor items such as pipeline allowance, loss, insurance, and purchasing fees omitted.

(ii) No account is taken of quality differences other than gravity (all crudes taken at 35° API) and sulphur content (all crudes under 0.6 per cent by weight).

(iii) Canadian and U.S. currencies taken at parity.

[a] Price posted at field gate.

[b] Interprovincial tariff payable 50 per cent in U.S. and 50 per cent in Canadian currency.

TABLE C-3

APPROXIMATE DELIVERED CRUDE OIL COSTS, JANUARY 1973 -- TOLEDO

(Dollars per Barrel)

	Canadian Redwater	Southern Louisiana	West Texas Sweet
Wellhead Price	$3.23[a]	$3.65	$3.58
Gathering	...	.05	.05
Pipeline Tariff	.55[b]	.28	.35
U.S. Import Duty	.105	...	...
	$3.88	$3.98	$3.98

Notes: (i) Approximate delivered crude costs based on published posted wellhead prices and ICC tariff rates. Minor items such as pipeline allowance, loss, insurance, and purchasing fees omitted.

(ii) No account is taken of quality differences other than gravity (all crudes taken at 35° API) and sulphur content (all crudes under 0.6 per cent by weight).

(iii) Canadian and U.S. currencies taken at parity.

[a] Price posted at field gate.

[b] Interprovincial tariff payable 60 per cent in U.S. and 40 per cent in Canadian currency.

TABLE C-4

APPROXIMATE DELIVERED CRUDE OIL COSTS, JANUARY 1973 -- ST. PAUL

(Dollars per Barrel)

	Canadian Redwater	North Dakota: Beaver Lodge	
		Devonian	Madison
Wellhead Price	\$3.23[a]	\$3.12	\$3.25
Gathering	...	.15	.15
Pipeline Tariff	.49[b]	.52	.52
U.S. Import Duty	.105	...	...
	\$3.82	\$3.79	\$3.92

Notes: (i) Approximate delivered crude costs based on published posted wellhead prices and ICC tariff rates. Minor items such as pipeline allowance, loss, insurance, and purchasing fees omitted.

(ii) No account is taken of quality differences other than gravity (all crudes taken at 35° API) and sulphur content (all crudes under 0.6 per cent by weight).

(iii) Canadian and U.S. currencies taken at parity.

[a] Price posted at field gate.

[b] Interprovincial tariff payable 70 per cent in U.S. and 30 per cent in Canadian currency.

TABLE C-5

APPROXIMATE DELIVERED CRUDE OIL COSTS, JANUARY 1973 -- PUGET SOUND

(Dollars per Barrel)

	Canadian Redwater	California Coastal	Alaska Kenai
Wellhead Price	$3.23[a]	$3.67	$3.20
Gathering	...	...	...
Pipeline Tariff	.40	.05	.08
Tanker Transportation	...	.26[b]	.33[b]
U.S. Import Duty	.105	...	...
	$3.74	$3.98	$3.61

Notes: (i) Approximate delivered crude costs based on published posted wellhead prices and ICC tariff rates. Minor items such as pipeline allowance, loss, insurance, and purchasing fees omitted.

(ii) No account is taken of quality differences other than gravity (all crudes taken at 35° API) and sulphur content (all crudes under 0.6 per cent by weight).

(iii) Canadian and U.S. currencies taken at parity.

[a] Price posted at field gate.

[b] Tanker transportation costs based on U.S. flag vessels at ATRS flat.

APPENDIX D

FOREIGN OIL EXPLORATION AND DEVELOPMENT BY NATIONAL COMPANIES OF IMPORTING COUNTRIES

1. In recent years, national companies -- both public and private -- of a number of major oil consuming/importing countries have become increasingly active in foreign oil exploration and development.* The governments of these countries have encouraged the development of oil resources abroad and have provided various forms of direct and indirect support to foreign oil operations of national companies -- e. g., subsidies and tax incentives. Beyond this, when and if a national company establishes a resource base abroad, this "national oil" may be accorded some form of preference in home markets.

2. This Appendix is intended to provide background information relevant to the possible interest of various national companies of oil-importing countries in development of Alberta tar sands. The Appendix first reviews the general objectives of oil importing countries and their national companies in foreign oil development. Then, a brief look is taken at the specific circumstances and scope of activities of the major Western European and Japanese national oil companies.

The Objectives

Private Companies

3. In recent years, a number of private oil companies from oil-consuming countries, especially Western European countries, have joined the search for oil abroad. For these companies, who are primarily engaged in refining and marketing, foreign exploration and development represents primarily an attempt to integrate upstream into crude production. The basic reason is that these companies see access to owned crude as necessary in order to compete successfully with the international majors -- and increasingly also U.S. "independents" -- in home markets.

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* The term "national company" does not include affiliates of major international oil companies operating in consumer/importing countries.

Governmental Policies

4. Governments of a number of oil-importing countries have sought to have a larger proportion of their oil imports met by supplies from national companies, both indirectly through support of foreign exploration efforts of private companies and directly through state-owned or state-controlled oil companies. The reasons are several.

5. First, oil imported by national companies can result in significant foreign exchange savings. The foreign exchange cost of such oil would be the outlays incurred by the national company abroad. This can be lower than the foreign exchange cost of other oil imports -- the full purchase price on oil purchased by national companies from foreign companies or the invoice price on oil imported directly by integrated foreign companies. *

6. There is also a desire by importing countries for geographic diversification of crude supplies for home markets. This is seen as providing greater security by lessening dependence upon relatively few sources whose supplies might be interrupted or otherwise constrained for one reason or another. The international oil companies do, of course, offer geographic diversification through their world-wide producing operations. However, diversification through national companies may provide an importing country with somewhat greater control over the origin of its oil imports. Governments, either through subsidized private companies or state entities, may have greater leeway in the size of the premium they are willing to pay for oil which offers potential security of supply. Where the premium is high -- i.e., the oil is high cost as compared with more prolific oil from the major producing areas of the Middle East and North Africa -- and "secure" oil of national companies may have difficulty in competing for outlets, preferred access may be given in home markets.

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* It should be noted, however, that the foreign exchange costs of exploration abroad by national companies can be very considerable in early years, owing to high initial outlays on exploration and development. Even after production is established, the savings could be long deferred to the extent that national companies reinvest profits from foreign production in further exploration or other ventures abroad.

7. Perhaps the most important reason for the interest of oil importing countries in direct access to foreign oil is that, rightly or wrongly, it is felt that "national" oil is somehow more secure than oil supplied by foreign companies to their local refining affiliates. "Political diversification" of imported oil supplies may be seen as at least as important as "geographic diversification."

8. Despite the expenditure of vast sums in an attempt to find and develop oil resources in virtually every corner of the globe, the international industry has not really succeeded in significantly reducing the dependence of the major oil importing countries of Europe and Japan on oil supplies from the politically unstable areas of the Near East. Furthermore, major importing countries have become concerned with the security of supplies provided by the international majors -- particularly the potential effect that the foreign policy of the home governments of these companies (the United States and the United Kingdom) may have on their status in the Arab world. This has provided impetus to efforts aimed at achieving greater participation in foreign oil production, which means investment abroad by national companies.

National Companies in Foreign Oil Operations

9. National companies from a number of oil importing countries are active in foreign oil operations. We consider here five of the largest and most important entities -- Germany's Deminex, France's ELF/ERAP, Italy's ENI, Spain's Hispanoil, and Japan's JPDC. For each, we review briefly their history and basic aims, the nature of home-government support, the magnitude of their outlays on foreign oil exploration/development, and the scope of their foreign operations (with particular note of any activity in Canada).

Deminex

10. Deminex (Deutsche Mineraloel Explorations GmbH) was originally formed in August, 1966 as a joint enterprise of eight German oil companies.* Each of the Deminex partners remains independent, while cooperating in the

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* The original participants and their equity shares were: Veba-Chemie 18.5%; Gelsenberg 18.5%; Wintershall 18.5%; Union Rheinische 13.5%; Schachtbau 10%; Preussag 7%; Saarbergwerke 9%; C. Deilmann 5%.

procurement of liquid hydrocarbons. The formation of Deminex was a direct result of the German Government's desire to maintain local independent's 25-per-cent share of Germany's marketing and refining operations. Independent refiner/marketers in Germany, as also in other Western European countries, had suffered competitively from a lack of direct access to crude supplies in line with their crude requirements. As a result, a number of independents had experienced financial difficulties and several had been taken over by international oil companies. The purpose of Deminex was to aid the German independents in developing their own crude supplies, thus bolstering their competitive position and hopefully forestalling any further erosion in their share of the German market.

11. The German Government encouraged the development of Deminex through the dispensement of awards under a loan-subsidy program which had begun in December, 1963. This program was introduced when Germany, under regulations of EEC Treaty's Mineral Oil Protocol, had to remove its $31.25/ton crude oil import tariff. To compensate German producers for the loss of government protection for their high-cost local oil production and to encourage efforts by German oil companies to obtain crude sources of their own, the program provided for subsidies and/or loans for both domestic production and foreign oil exploration. Under this program, qualifying companies could be reimbursed for up to 75 per cent of their foreign exploration costs.* These reimbursements were in the form of loans repayable only if exploration was successful and only from revenue from the producing concessions involved. Government also had the option to waive repayment, depending on the financial position of the borrowing company.

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* Under the program, loans for foreign exploration are not given automatically, but only for those projects which the Federal Economics Ministry considers "promotion-worthy." The Government may exclude companies from the exploration subsidy scheme if they have adequate "other" financing means. This has allowed German authorities to prevent international oil companies from financing oil exploration through their German subsidiaries with German tax funds. In addition, loans were only available to companies that had been exploring for oil within West Germany in the years from 1959 to 1962 or that had been processing at least 5 per cent of crude oil produced within Western Germany and were willing to continue such processing.

12. In 1964 and 1965, prior to the formation of Deminex, the German Government made available to local firms subsidies amounting to approximately $50 million under this program. Deminex was expected to begin its foreign exploration in 1966 with a large portion of its money to be provided by Government subsidies. However, due to an economic recession and Government budgetary stringencies, subsidies were virtually eliminated in the 1966-1968 period, severely limiting the efforts of Deminex.

13. In 1969, Deminex was dismantled in favor of a new association, so-called Deminex II (Deutsche Erdoelversorgungs GmbH). The participants and aims were basically the same as those of the original group formed in 1966.* The specific activities that Deminex II was to engage in were set out as (1) exploration for crude oil and natural gas outside the EEC, (2) purchase of and/or participation in producing oil and gas fields, (3) arrangement of long-term crude-oil purchasing agreements, and (4) transport of crude oil to Germany.

14. However, this time the German Government placed at the disposal of the new company $145 million in aid to be used over the six-year period 1969 through 1974. Approximately $25 million was budgeted for the first two years, with $30 million budgeted for each of the following four years. In addition to the above, Deminex was expected to spend $500 million of its own participants' funds over the six-year period.

15. The current reimbursement plan is basically similar to the original 1963 program. Government can lend up to 75 per cent of the total cost of approved foreign exploration projects, with repayments only if oil or gas is

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* At present, the only difference in ownership from the original group is Union Rheinische's acquisition of C. Deilmann's 5-per-cent share. Through ownership in various participants, German federal and regional governments hold a 30-per-cent interest in Deminex.

found in commercial quantities. The Government can also contribute up to 30 per cent (within the limits of $145 million) of the costs involved in purchases from other oil firms of existing production or exploration rights.*

16. Currently, Deminex holds exploration rights in Indonesia, Trinidad, Nigeria, Senegal, the North Sea and the Canadian Far North.** The group has also expressed interest in acquiring exploration rights in Venezuela, Peru, Iran, Saudi Arabia and Iraq. However, to date, Deminex has not yet found any new crude resources.***

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* In 1972, Deminex considered acquisition of a 20-per-cent share in British Petroleum's two-thirds interest in Abu Dhabi Marine Areas. This interest in an established Persian Gulf producing concession would have provided Deminex with somewhat over 50,000 barrels daily of crude production initially, with the prospect of very substantial increases in production in the future. The purchase price was reported to be in the region of $150 to $200 million. The purchase, which would have required the approval of all Deminex participants, was subsequently vetoed by Veba-Chemie. Upward revisions in cost estimates and uncertainties over the impact of participation by the Abu Dhabi Government in the concession were reported to have been major factors in the rejection, as well as apparent doubts on the part of the German Government as to whether to furnish the necessary financial aid. After the rejection by Deminex, a consortium of Japanese companies signed an agreement with BP to acquire a share in the Abu Dhabi concession (of which more later).

** In the Canadian Arctic, Deminex has taken a farmout from the Panarctic Oils group. It has varying interests in acreage on four Arctic Islands -- Amund, Ellesmere, Cornwallis and Somerset. Its holdings consist of four blocks with 1.1 million gross acres, of which a maximum of 200,000 net acres (18 per cent) can be earned by Deminex. The group has a commitment to drill four wells totaling 42,000 feet on the Panarctic acreage. Deminex also obtained a 10-per-cent interest on the Fosheim and Amund Central Dome Structure, and acquired 50-per-cent interest in Amoco's Banks Island acreage.

*** However, individual members of Deminex have had some success on their own in establishing foreign crude resources. Gelsenberg has producing concessions in Libya and The Netherlands; Wintershall in Canada, Peru and offshore Dubai; and Union Rheinische in the British North Sea.

ELF/ERAP

17. France's state-owned ERAP (Entreprise de Recherches et d'Activites Petrolieres) was formed in 1966 by the merger of two French company groups RAP (Regie Autonome des Petroles) and BRP (Bureau de Recherches de Petrole). The objective was to amalgamate existing State oil enterprises into a single group with integrated operations covering all phases of the petroleum industry.* The trademark ELF was adopted in 1967 in order to simplify the identification of ERAP's many affiliates and subsidiaries around the world.

18. At the outset, the ELF/ERAP Group had a substantial crude producing position, owing to successful exploration carried out by its predecessor organizations -- particularly in Algeria. These overseas exploration efforts were the result of France's postwar aim of achieving "self-sufficiency" in oil production -- i.e., control by French companies of crude oil resources equal to France's domestic oil consumption. By 1970, this objective had been achieved. However, in early 1971, Algeria nationalized a large part of French-company interests in Algerian crude production, leaving France far short of self-sufficiency. Prior to nationalization, ELF/ERAP had obtained some 80 per cent of its crude from Algeria. Of this, about two-thirds (some 350-400,000 barrels daily) was lost through nationalization.

19. In order to make up for production nationalized in Algeria and meet rising French oil requirements, ELF/ERAP has been urged by the French Government to intensify its efforts at diversifying its crude sources. According to press reports, particular emphasis is to be given to further exploration of the European continental shelf, drilling in deeper waters, and participating in North American oil shale and tar sands.***

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* The French Government also holds a 35-per-cent interest in Compagnie Francaise des Petroles (CFP), an integrated international oil company. However, CFP conducts its worldwide operations independently of the ELF/ERAP Group.

** SNPA (Societe Nationale des Petroles d'Aquitaine), which is 51-per-cent owned by ELF/ERAP, conducts worldwide operations as an independent entity under its own name.

*** It should be noted that this would not be the first involvement of French companies in oil shale development. In the mid-1960's, wholly-owned subsidiaries of RAP and SNPA each held approximately 5-per-cent equity shares in The Oil Shale Corporation (TOSCO), which has been actively involved in research and development of Western U.S. oil shale reserves. Also, SNPA through its affiliate, Australian Aquitaine Petroleum Pty. Ltd., has been a partner in a joint venture with TOSCO and Pacminex Pty. Ltd., in the development of oil shale deposits (and vanadium) in the area of Julia Creek (Queensland), Australia.

20. The ELF/ERAP Group has stated that it would require expenditures of something like $75 to $100 million annually for five years to develop new sources of production adequate to compensate for the loss of production in Algeria and provide for continued expansion. This compares with direct subsidies ELF/ERAP received from the French Government's Hydrocarbon Support Fund (Fonds de Soutien aux Hydrocarbures) in 1971 and 1972 of about $36 million per year.* This same level of subsidy will reportedly be maintained in 1973. The level of direct Government funding beyond 1973 has not yet been decided.

21. In its effort to find sources of hydrocarbons abroad, the ELF Group has acquired exploration rights in 34 foreign countries.** In addition to Algeria, production has been established from its holdings in Libya, Tunisia, Gabon, Congo, Nigeria, Morocco, the North Sea and Canada. The Group has also reportedly shown interest in acquiring acreage in Egypt, Peru, Trinidad and Venezuela.

22. In seeking foreign exploration/development rights, ELF/ERAP and its predecessor companies have been active in working out new types of arrangements with host governments. In 1965, for example, AUXIRAP (a subsidiary of RAP) signed a partnership arrangement with the Saudi Arabian state oil company Petromin, which included among other terms a 20-per-cent royalty, as against the standard 12 1/2 per cent. Even more significant, in 1966, ELF/ERAP entered into the first "contract" arrangement in the Middle East with the National Iranian Oil Company and later concluded a similar arrangement with the Iraqi National Oil Company in 1968. Under these arrangements, ELF/ERAP acts as a contractor for the producing government oil company, undertaking exploration with funds it advances to the government company in the form of interest - free loans repayable only in the event of success. One half of all oil discovered is set aside as "national reserve," for the exclusive use of the government oil company. For its efforts, ELF/ERAP would be entitled to buy from the government company specified volumes of crude on attractive terms, but would also be obligated to dispose of specified volumes of government-company crude as a "broker."

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* Direct subsidies from the Fund were substantially higher in earlier years, but have been declining. In its first year of operation (1966), ELF/ERAP received about $70 million, declining to $45 million by 1970. The French Government would reportedly like the ELF/ERAP Group to become financially "self-sufficient" so that eventually subsidies can be eliminated.

** Italy, West Germany, Spain, United Kingdom, Netherlands, Norway, Switzerland, Algeria, Libya, Tunisia, Nigeria, Gabon, Spanish Sahara, Cameroon, Congo, South West Africa, Morocco, Somalia, Tanzania, Malagasy, Mozambique, Saudi Arabia, Iraq, Iran, Cambodia, Malaysia, Australia, New Zealand, United States, Canada, Costa Rica, Surinam, Fr. Guiana and Argentina.

23. The ELF/ERAP Group's efforts in Canada date back to 1962 (at the time through BRP). At present, the Group through its subsidiary Elf Oil Exploration and Production Canada, Ltd. holds exploration acreage in Alberta, Saskatchewan, British Columbia, the Mackenzie Delta, Hudson Bay, the Beaufort Sea, East Coast offshore and the Arctic Islands.

ENI

24. ENI (Ente Nazionale Idrocarburi) is a corporation wholly owned by the Republic of Italy. It was originally created in February, 1953 to promote and effect new activities in the national interest in the field of hydrocarbons and natural steam and to explore and exploit hydrocarbon deposits in the Po Valley.

25. Since 1953, the Italian Government has endowed ENI with additional corporate powers to carry out activities in the fields of chemicals, textiles and nuclear fuel. Though essentially free to conduct current operations with the flexibility of a private enterprise, ENI has the obligation to account to the Italian Government and Parliament for all its activities. In particular, its investment plans must be approved some years before actual investments are made by the Ministry of State Holdings, which forwards them to the Ministry of Budget and Economic Planning. Here, the plans are examined from the standpoint of whether they conform with the objectives of the centrally planned national economy and the institutional objectives prescribed by Parliament in ENI's Charter of Incorporation.

26. ENI operates through some 160 subsidiaries and associated companies incorporated in approximately 90 countries. The companies are grouped under nine principal subsidiary corporations.* The subsidiaries are independently operated companies which depend upon ENI for assistance in formulating investment policy, financing, and long-range planning. Their activities conform with group strategy in both national and international operations.

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* AGIP -- Oil and natural gas exploration and production; petroleum product marketing; and motel chain. ANIC -- Refining, petrochemical and chemical production; petrochemical product sales. SNAM -- Natural gas transmission, distribution and sales; oil tanker fleet operation; pipeline operation. AGIP Nucleare -- Nuclear fuels exploration, production and sales. Nuovo Pignone -- Mechanical manufacturing; equipment for refineries and petrochemical plants. SNAM Progetti -- Engineering, process licensing R&C laboratories. SAIPEM -- Construction of plant and pipelines; drilling; and offshore fleet operation. Lanerossi -- Textiles, processing of medium and heavy fabrics, clothing, carpets and blankets. SOFID -- Domestic financing for oil and natural gas exploration, production and marketing.

27. Over the past decade and a half, ENI has directed a substantial part of its investment outlays toward foreign oil exploration. The objectives have been to "highly diversify and increase self-sufficiency in supplies, if possible from every quarter of the globe." In its foreign exploration/development efforts, ENI has stressed direct government-to-government relations, endeavoring to by-pass the international oil companies by establishing new types of relationships between petroleum consuming countries and producing countries. In 1957, for example, ENI pioneered the so-called joint venture or partnership arrangement with Iran, this representing the first break with the older concession-type arrangement. More recently, ENI concluded an agreement under which the Libyan Government will acquire a 50-per-cent participation interest in two of ENI's producing concessions in that country.

28. ENI has acquired over 250 million acres in over 20 countries in its search for hydrocarbon deposits.* It has established production in Libya, Nigeria, Congo, Tunisia, Qatar, Iran and the North Sea. However, ENI is still far from self-sufficient. In 1971, ENI's refinery crude requirements came to some 600,000 barrels daily (of which some 430,000 barrels per day was in Italy, 170,000 barrels daily abroad), but its worldwide production was only about 240,000 barrels per day.

29. In the period 1968-1970, ENI spent approximately $375 million on hydrocarbon exploration and production abroad or about $125 million annually. Planned expenditures for the same purposes during the period 1971 to 1975 are expected to be around $1,200 million, $240 million annually.

Hispanoil

30. The Spanish Government, faced with relatively unsuccessful exploration at home and a rapid growth in local consumption, has encouraged Spanish companies to broaden their search for liquid hydrocarbons to include foreign countries. In 1965, Hispanoil (Hispanica de Petroleos) was formed

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* The following are areas in which ENI has exploration acreage: North Sea, Greenland, Abu Dhabi, Saudi Arabia, Qatar, Iran, Egypt, Libya, Tunisia, Nigeria, Congo, Tanzania, Malagasy, Mauritania, Zaire, Indonesia, Thailand, Colombia, Argentina, Trinidad and the United States. In Canada, ENI -- throug its subsidiary AGIP -- has acquired a 10-per-cent interest in 33 million acres of offshore permits around Labrador.

by a group of local refiners and the Fierro banking group.* The Spanish Government directs the policies of Hispanoil -- which is designated as the Government's official agency for foreign exploration -- through its majority equity holdings in various participants. The objectives of Government have been to reduce the cost of Spain's oil imports and to secure "safe" sources of foreign oil supplies through diversification and State control over imported supplies.**

31. The Spanish Government has given Hispanoil the right to make suitable barter arrangements in respect of up to 30 per cent of the country's crude oil needs, including the needs of refineries not participating in Hispanoil itself. In the event of commercial production from Hispanoil's foreign ventures, the Spanish Government has shown a willingness to give preference to such crude in its home market -- e.g., Hispanoil has a guarantee of 25 per cent of the Spanish market through 1985 for any oil discovered in Kuwait under a joint venture arrangement with the Kuwait Government.

32. In 1966, Hispanoil began its exploration efforts abroad in Libya, where it obtained a 42-per-cent interest in two concessions. Since 1966 Hispanoil has obtained exploration acreage in Kuwait, Iran, Egypt, and the North Sea. Other countries where Hispanoil has reportedly shown an interest in obtaining exploration rights include Algeria, Iraq, Saudi Arabia, Peru and Venezuela. In 1969, Hispanoil acquired a 50-per-cent interest in Dubai Marine areas, a Persian Gulf concession on which production had been established.

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* Equity participation in Hispanoil is currently:

51.0%	Instituto Nacional de Industria (INI; Spanish Government's State Industrial Agency)
12.7%	CEPSA (Compania Espanola de Petroleos)
10.0%	Iberica de Petroleos
20.0%	Iberica Refinadara de Petroleos
6.3%	Financiera Fierro

It is reported that INI is to acquire an additional 19 per cent interest in Hispanoil through its purchase of CEPSA and Financiera Fierro's equity shares.

** Press reports indicate that Spain is also considering entering foreign exploration through Campsa, an agency which administers the State oil marketing monopoly.

33. At present, Hispanoil's only production is from Libya and Dubai. Current production by Hispanoil in these two countries averages about 40,000 barrels daily. This compares with total oil consumption in Spain of somewhat over 600,000 barrels per day.

34. In 1971, Hispanoil spent approximately $14 million on production and exploration abroad. In 1972, spending is expected to be some $21 million.

JPDC

35. Over the postwar years, Japanese energy requirements have increased very rapidly, with most of the increased requirements met by oil imported from abroad. The bulk of imported oil has been supplied by the international oil companies, with the largest part from the Middle East. Mounting Japanese Government concern with the cost and security of its oil imports led to the passage of the Petroleum Development Public Corporation Law in October, 1967. This law created the Japan Petroleum Development Corporation (JPDC), wholly state owned, whose function is to coordinate and promote exploration and development of petroleum resources abroad by Japanese interests. The objectives were to ensure low-cost and secure foreign oil supplies through diversification of sources and direct access to foreign oil by Japanese companies. The Government's stated aim was to have Japanese-owned oil account for at least 30 per cent of total Japanese crude oil requirements by 1985.

36. As originally set out in the 1967 Law, JPDC was not permitted to engage directly in exploration/development operations, though it could acquire equity in companies that did engage in such activities. Its operations were for the most part limited to providing investment and loan funds to Japanese-controlled companies for exploration in foreign countries as well as the continental shelf off Japan.* In addition, JPDC could guarantee liability for funds

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* JPDC's loans carry an annual rate of interest of 6.5 per cent and are repayable in 18 years, including a grace period of up to eight years. The loan need not be repaid in the event of unsuccessful exploration.

provided by private banks to oil development projects. In 1972 the Development Law was partially revised, expanding the scope of JPDC's activities to include financing of natural gas projects and direct participation in exploration for oil and gas resources in overseas areas.[*]

37. Japanese companies are engaged in oil exploration/development, through some forty entities in fourteen foreign countries.[**] They have established production in both Saudi Arabia and Indonesia. However, combined production of Japanese companies abroad currently represents only some 10 per cent of total Japanese crude oil imports.[***]

38. Where production has been established abroad by Japanese companies, Japanese authorities have been willing to give such "national oil" preferential treatment in the Japanese market. Since 1962, Japanese refiners have been obligated to take Arabian Oil Company's Saudi Arabian crude under an allocation scheme established by the Japanese Government. This preferential status is scheduled to expire this year, but this is owing in part to the high sulphur content of this crude oil, which poses serious air-pollution problems in Japan.

39. JPDC's total capital expenditures for 1972 were budgeted for approximately $70 million -- as against $50 million in 1971 and $40 million in 1970.

40. Recent developments in world oil have given added impetus to Japan's efforts to secure access to foreign oil. In connection with the June, 1972 revisions in the Development Law, giving JPDC the authority to engage in direct acquisition of foreign oil rights, the Japanese Diet passed the following supplementary resolution --

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[*] Reflecting this change, JPDC is reportedly expected to sign a production-sharing contract with the Peruvian state oil company, Petroperu, for the exploration and development of a 10,000 square kilometer area in southern Peru. If consummated, this would be JPDC's first direct involvement in foreign exploration.

[**] Qatar, Iran, Saudi Arabia, Abu Dhabi, Egypt, Nigeria, Zaire, Colombia, Australia, Indonesia, Thailand, Malaysia, Canada and the United States.

[***] In addition, a Japanese company has established commercial reserves in Abu Dhabi, with production scheduled to begin this year.

> The Government is requested to take aggressive steps in Japan's exploration and development of petroleum resources in foreign countries in its organic harmony with her economic cooperation with those countries, promotion of oil exploration and development in the continental shelf off Japan, utilization of the nation's surplus foreign exchange reserve for development of oil and other key resources, to cope with rapid changes in the environment surrounding the oil industry, both at home and abroad, thereby assuring steady supply of petroleum at low cost.

41. In order to assure implementation of this resolution, JPDC's operational functions are to be expanded by an increase in its capital investment and/or loan funds and enlargement of its organization and personnel. More important, in an apparent effort to take "aggressive steps" in development of foreign petroleum reserves, the Japanese very recently entered into an agreement to purchase a substantial interest in an established Middle East concession. A consortium of Japanese companies will acquire a 22.5-per-cent interest in the offshore producing concession of Abu Dhabi Marine Areas from British Petroleum at an indicated price of $780 million.* JPDC and the Export-Import Bank will reportedly provide 70 per cent of the total investment and Japanese private interests the remaining 30 per cent. The initial share of the Japanese companies in production from this concession will be somewhat over 100,000 barrels daily, but with prospects for substantial increases over the years immediately ahead.

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* The Japanese will purchase 45 per cent of BP's two-thirds interest in the concession, or 30 per cent of the total concession. But this will be reduced to 22.5 per cent after the Abu Dhabi Government acquires a 25-per-cent interest in the concession under the recently agreed upon "participation" arrangement. It should be noted that the sum of money involved in the Japanese purchase of an interest in the Abu Dhabi concession cannot really be compared with the reported Deminex offer cited earlier. These figures, are based upon press reports, not official documents, and are meant to be illustrative only of the orders of magnitude of funds that national companies may be willing to commit to development of oil resources abroad. The terms and conditions of the Japanese arrangement may be substantially different from those of the earlier Deminex deal, particularly with respect to the residual Japanese interest after participation by the Abu Dhabi Government in the concession.

42. The efforts of the Japanese in Canada date back to 1966.* At that time, Japex Canada, Ltd. (a company owned 29.3 per cent by JPDC and 70.7 per cent by Japex**) entered into a modest exploration effort with Pinnacle Petroleum, Ltd. of Canada. In 1969, this agreement was cancelled, with Japex Canada continuing on its own. Japex Canada's capital expenditures so far have totalled some $3.5 million. However, to date, no commercial discoveries have been made.

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* From time to time, the Japanese have expressed interest in Alberta tar sands development. However, we do not deal in this Appendix with the various approaches made by the Japanese over the years. In the main text, we consider the potential future interest of the Japanese and other oil-importing countries in the tar sands.

** JPDC holds a 65.7-per-cent equity interest in the Japan Petroleum Exploration Company (Japex). Japex was originally formed in 1955 with part government ownership. Its main objectives were to explore and develop Japanese natural gas and petroleum resources. When JPDC was organized in 1967, it operated through Japex. In 1970, Japex became once again an independent entity which now carries on exploration both at home and abroad.

APPENDIX E

FOREIGN CONCESSIONARY DEVELOPMENTS

1. The upward pressure on foreign oil prices in recent years has come not from tightness of supplies but from escalating "take" by producing governments. In the relatively brief period since the late Summer of 1970, the world oil industry has been dramatically altered by unprecedented demands upon the international oil industry, dramatic confrontations with threatened withholding of essential oil supplies, and far-reaching settlements concluded under duress.

2. Political implications are especially significant. First, Libya unilaterally seized the opportunity that stemmed from company dependence and European exposure. These followed from unusually rapid exploitation of Libyan reserves and the consequent disproportionately large share of European supplies drawn from Libya. After Libyan demands were met, OPEC unity became a political imperative for Middle East Governments, resulting in the so-called "Teheran settlement."* The monopoly power inherent in OPEC unity was not lost upon producing countries. It became further evidenced in the "currency" and "participation" agreements -- both within two years after the Teheran settlement had promised five years of fiscal stability.

3. This Appendix reviews recent concessionary developments in major producing countries and their portents for the future. The emphasis is not so much on the specific terms that these producing governments have managed to wrest from the oil companies, but on the economic and political implications of their initiatives. More specifically, these implications revolve around the questions of (i) current and future oil costs, and (ii) the shifting balance of political power away from the concessionary companies toward the host governments.

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* OPEC, the Organization of Petroleum Exporting Countries, was founded in August of 1960. OPEC member nations currently include: Abu Dhabi, Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia and Venezuela.

The OPEC Rounds of 1970-1971

4. Libya unilaterally first precipitated and then capped the rapid fire sequence of events. Its opportunity was Europe's undue dependence on Libyan oil, upwards of 30 per cent of Europe's total oil imports. The consequences of Tapline closure, of Libya's own forced crude production cutbacks (in the name of "conservation"), and of the resulting tanker and world crude supply stringencies were all magnified by the degree of European dependency.*

5. The first Libyan settlement in Tripoli, September 1970 resulted in a major increase in tax-paid costs for the companies operating there. Briefly --

> The companies agreed to increase posted prices by 30 cents per barrel,**
>
> Price escalation was provided at the rate of two cents per barrel per annum for five years.

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* Tapline, one of the Middle East's major crude pipelines, normally carries about 475,000 barrels daily of crude oil from the Arabian American Oil Company's (Aramco's) fields in Saudi Arabia to the Mediterranean terminal at Sidon, Lebanon. The closure of Tapline (from May 3, 1970 to January 29, 1971) together with production cutbacks in Libya (totaling about 800,000 barrels per day over the period May-September 1970) forced companies to substantially increase shipments of long-haul crude out of the Middle East (via the Cape of Good Hope) to Western Europe. The resulting sharp increase in demand for tanker tonnage was reflected in significantly higher average world crude oil transportation costs.

** Outside of North America, posted prices are published prices for crude which are set by the seller, fob export terminals. Up to the early 1950's and during the short supply crisis following the closure of the Suez Canal in 1956, these posted prices represented prices at which such producers were willing to sell and purchasers expected to buy tanker cargo lots. But as the supply of oil ran ahead of demand, competition for armslength sales became more acute. Despite a significant reduction in the posted prices of Middle Eastern crudes over the period from September 1957 until August 1960, progressively larger discounts were allowed off posted prices on important third party sales and netbacks to producing countries on crude moving into integrated channels were increasingly below posted prices. After August 1960, OPEC was successful in preventing further reductions in posted prices -- on which their government oil revenues were largely based -- despite continued decline in realized prices. Thus, posted prices no longer have any meaningful relationship with market prices, but continue to serve as a reference price for royalty and income tax purposes in most major producing countries.

> Most companies agreed to extinguish the Government's back-tax claims by acquiescing to a surtax on future production ranging from 4 to 8 per cent, which raised the companies' effective income tax rates from 50 to 54-58 per cent.

As a result of this settlement, assuming average production costs of around 30 cents per barrel, the immediate increase in tax-paid costs for 40° API Libyan crude came to a little over 25 cents a barrel.

6. Looked at objectively, the 1970 settlement involved an adjustment of Libyan crude values that had been at issue since the initial postings for Libyan crude in 1961. In effect, the new higher postings, at least implicitly, entailed a realignment of Libyan prices with Persian Gulf quotations, as well as allowance for quality and transport advantages. In an economic context, the settlement was hardly revolutionary, although it probably exceeded by a considerable margin what the industry could have negotiated earlier.

7. At the time, however, the increases in Libyan postings and the companies' tax payments stood out as unprecedented gains by a producing government (although they were to be dwarfed by a second Libyan settlement barely a half year later). Libya's success contrasted strikingly with OPEC's inability in its ten-year history to get posted prices up, despite that restoration of the 1960 reductions in Persian Gulf postings was OPEC's first order of business. The political implications of the Libyan settlement were thus to be far more significant than the economic costs. Libya was able to take advantage of a special combination of circumstances, as discussed above, to impose its demands in short order upon an international industry (independents and majors alike) with hardly any effective opposition from producing companies or consuming countries.

8. In anticipation of reciprocal actions by other producing governments, following upon the first Libyan settlement, the companies voluntarily increased the posted prices of other short-haul crudes -- by 20 cents at

Eastern Mediterranean terminals and by 25 cents in Nigeria. Persian Gulf heavy crudes were also increased modestly. Most significant, a 55-per-cent tax rate was tendered to the Persian Gulf producing countries.

9. But all this was to be a futile gesture. It was not just that Libya's fiscal gains were an inevitable target for other producing countries. Nor even that Libyan success spurred others to emulate. The blunt and realistic fact was that Persian Gulf producing countries, which had heretofore played a moderate role, were pressed to show that they could gain at least as much as Libya and as expeditiously. In effect, the unity of OPEC became a political imperative for precisely those producing countries that previously had been a moderating influence in industry-government relations.

10. Venezuela, in December 1970, enacted an increase in its statutory tax rate from 52 to 60 per cent, retroactive for all of 1970. At the same time, the Executive was authorized unilaterally to annually determine tax-reference prices; new reference values were promulgated in March 1971, with the largest increases for heavy crudes and products then enhanced by the straitened circumstances of world oil trade.

11. Against this background, an OPEC session convened in Caracas in December, 1970. OPEC then not only resolved that its Persian Gulf members should achieve their objectives under threat of united withholding of production from recalcitrant companies, but set a close deadline for the companies' acquiescence.

12. By February 1971, the Teheran Agreement was whacked out. The main terms included --

An immediate increase of 35 cents per barrel in the posted prices of Persian Gulf crudes;

A new gravity system involving the reduction of the previous 2 cents a barrel per degree differential to 1.5 cents;

Elimination of the OPEC "discount allowances";*

An annual escalation in postings in each of the years 1973 through 1975 at the rate of 2.5 per cent plus 5 cents per barrel; and

The 55-per-cent income tax rate was ensconced.

As a pro quid quo to the companies, the Gulf States gave a promise of no "leapfrogging" over later terms that might be established in other producing countries and five-years' fiscal stability. Stability guarantees, however, proved to be illusory.

13. The political implications of the Teheran agreement were even of greater consequence. Threats by OPEC to withhold oil supplies from concession-holding companies (but not necessarily consuming countries) if demands were not met and the strength of OPEC unity gave striking evidence of what could be accomplished by the joint action of producing governments. And the success which it achieved gave OPEC the confidence subsequently to pursue additional demands on the currency question and on participation (of which more later).

14. Through all this, Libya was setting out a whole new set of demands, notably for a further increase in posted prices that dwarfed those preceding, and for compulsory reinvestment within Libya. The second Tripoli Agreement of April, 1971 set forth the following --

The Libyan income tax rate was increased to a uniform 55 per cent;

The surtax payments from the previous agreement were replaced by a "supplemental" payment that averaged 9 cents per barrel of production (the so-called "retroactive buy-out");

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* In connection with an earlier agreement with OPEC countries on the tax treatment of royalty payments, certain discounts had been allowed off posted prices for tax-accounting purposes.

A further increase in posted prices of 90 cents, of which 12 cents was a temporary premium linked to the closing of the Suez Canal and 13 cents was a variable freight premium which was to be adjusted quarterly on the basis of average tanker freight rates; and

An annual escalation in postings in each of the years 1973 through 1975 at the rate of 2.5 per cent plus five cents per barrel (the two cents-per-year escalation of the first Tripoli settlement was retained as a low-sulphur premium!).

15. This agreement with Libya was subsequently followed by similar agreements with Nigeria, and with Saudi Arabia and Iraq for crude lifted from the Eastern Mediterranean export terminals. Then in December 1971, Venezuela decreed still higher tax-reference values and a system of penalties for failure to meet prescribed levels of export sales volume -- on both the high and low side. Although the specific terms of these various agreements differed somewhat, the overall effect was the same in all the OPEC countries -- an unprecedented increase in government "take" on crude oil production.*

16. It is not, however, the run-up of foreign producing costs that is in itself most significant. Indeed, producing companies were able, in the environment of late 1970, and since, to recover the increased costs and to improve integrated profit margins at the same time. More important are the lessons that will have been impressed upon OPEC -- not that they were previously unknown, but now solidly evidenced. First, that the role of OPEC is not to bargain over sharing of profits; by the latter 1960's the combination of increased government take and competitive pressure on prices had squeezed integrated profits about as much as practicable. Rather, OPEC's concern would henceforth be with government oil revenues per se; leave it to the producing companies to recover their profit margins by putting up crude and product prices downstream.

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* Indonesian contractual relations are in the form of "production sharing contracts" rather than traditional concessionary arrangements. Crude values on these contracts are determined by the realized prices of contractors on sales to non-affiliates. In recent years, however, the actual basis for price determination, in effect, has been the setting of prices by the Indonesian state company, Pertamina. The substantial hikes in government take achieved by other OPEC members have thus provided Pertamina with the opportunities to raise prices and hence the value of its share of crude production. But under the Indonesian contract system, these higher prices also work to the benefit of the private contracting companies by raising the value of their own share of production.

17. Second, that OPEC unity can work, at least when there are common demands to be put upon concession-holding companies. Neither industry nor consuming countries have much countervailing power, and the industry's interests may, in the final analysis, run more with producing countries -- to protect concessionary reserves and hopefully to benefit from higher prices -- than with consuming-country customers.

18. Third, that the advantage of quality or location ought to accrue to a producing country, not to concession-holding companies. This is strikingly evidenced in the renegotiated pricing and tax provisions for Libyan and Nigerian crude. In effect, the tax-paid costs of these crudes are "designed" to achieve c.i.f. parity with Persian Gulf crudes in Western Europe, having regard for respective transportation and quality differentials. On this basis, the economic advantage which had accrued, at least in part, to producing companies is now hypothecated to producing countries. No matter that Libya has, in practice, over-costed her crude, and is suffering loss of production. The principle is there, and it will not be lost upon governments of other producing countries.

19. In sum, the experience of 1970-71 points to a new strategic approach by OPEC in which the emphasis is on increases in government take, without undue concern about resulting corporate margins; and a new appreciation of the political leverage that OPEC can wield. These are portents for the future. That the industry, to now, has been able to rationalize the settlements and to put its higher costs upon its customers is probably less significant, so far as concerns the next round of concessionary issues.

Currency Revaluation Adjustment

20. After the U.S. move toward currency revaluation in August 1971, OPEC pressed aggressively for adjustment of crude oil postings so as to compensate producing countries for the lower purchasing power of their oil revenues. The companies argued that the Teheran Agreement already provided price escalation in anticipation of projected declines in the purchasing power of oil revenues; and that in any event the promise of fiscal stability through 1975 should preclude such further demands. Not so, answered OPEC; escalation was for inflation, and hardly adequate in any case; currency revaluation is separate and apart, and should impel price adjustments in consequence. And with its superior bargaining leverage, the OPEC position was conceded with but nominal debate over the appropriate percentage increase in postings.

21. The Geneva settlement of January 1972 thus again raised posted prices at oil export terminals in the Persian Gulf and the Eastern Mediterranean. The main terms of the agreement included --

> An immediate increase in postings of 8.49 per cent; and
>
> In the future, posted prices would be adjusted quarterly (starting March 1, 1972) in response to changes in exchange rates in accordance with an agreed currency-parity index.*

Similar dollar parity agreements were subsequently worked out in Libya and Nigeria. In Venezuela, the new tax-reference prices, which were set in December 1971, had already taken into account the upward revaluation of the Bolivar in terms of the U.S. dollar.

22. The effects of changes in major concession terms since July 1970 upon the posted prices and tax-paid costs of selected crudes are set out in Appendix Table E-1. The most recent figures are as of January 1, 1973 and thus include both the recent OPEC escalations as well as the latest annual escalation in Venezuelan tax-reference prices. Compared with the third quarter of 1970, tax-paid costs of company equity oil have risen by some 60 cents per barrel for Arabian light and 64 cents for Kuwait crude. Venezuelan crudes are up about 75 cents per barrel; Nigerian crude is up by $1.00; Libyan by around $1.10.

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* This index represents in percentage terms the arithmetic average appreciation of the currencies of nine major industrialized countries vis-a-vis the U.S. dollar since April 30, 1971. The nine countries are Great Britain, France, West Germany, Italy, Japan, Belgium, Holland, Sweden and Switzerland. Postings will not be changed unless the index reaches 2 percentage points above or below "the starting average" of plus 11.02 per cent. At the same time, posted prices are not to fall below the level that would have prevailed according to the original Teheran terms.

23. Again, the significance of the various agreements concluded over the last few years lies not so much in the immediate economic terms. More important, OPEC has itself experienced and evidenced to others its ability to impose the terms of settlement by resort to unified demands -- of common interest to producing governments and commonly imposed on producing companies.

Participation

24. The basic principle of participation was formally set out by OPEC as long ago as June 1968. As conceived by the producing-country governments, participation means a share in the ownership and active management of established concessions, together with the right of exporting their own equity share of production. Irrespective of the initial equity share achieved by the producing countries, the long-run objective was clearly to establish control and ultimate total ownership over their producing operations. Further, the government partner would carry added weight as both landlord and sovereign. Taken together, these were bound to enhance the strategic role of governments in concessionary operations and planning at the expense of the companies. In this respect, participation went far beyond all the other previous OPEC demands, which focused largely on financial issues.

25. In March 1972, the right of participation by producing governments in established concessions was conceded in principle by Aramco in Saudi Arabia.* After a difficult period of negotiations, a General Agreement on Participation

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*It should be noted, however, that not all of the OPEC member nations appear to be interested in participation, at least at this time. Iran was not covered by participation and it is currently involved in difficult negotiations with the Consortium companies over new arrangements for the future, which might well result in another round of "leapfrogging" in financial benefits to all major producing countries, with inevitably higher oil prices. Meanwhile, Venezuela, which may still consider participation, has anticipated the 1983-84 expiration of major concessions by passing a Reversion Law in the Summer of 1971. Among other provisions, a Guarantee Fund financed out of after-tax earnings of each company has been established to insure proper maintenance of company facilities. Indonesian contracts are on a production-sharing basis and the concept of participation as now being applied in the Persian Gulf would not seem to be readily applicable. Finally, Algeria already has achieved total or majority ownership in all of its producing concessions through nationalization.

was signed by the major operating companies and the Governments of Saudi Arabia, Abu Dhabi, Qatar and Kuwait, although final agreement in Kuwait is still subject to approval by the Kuwaiti National Assembly.* The four countries acquired an initial 25-per-cent ownership interest in the major crude producing concessions in their territories as of January 1, 1973. In return, the Governments agreed to pay compensation to the companies in an amount equal to 25 per cent of the "updated" net book value of their production investments.** In addition, participating Governments will henceforth be responsible for their shares of all operating costs and future exploration and development expenditures.

26. The producing Governments also have options to annually acquire five additional equity increments as from January 1, 1978. If all compensation payments and notices to acquire this additional equity are made on time, Governments would acquire full 51-per-cent participation by 1982, as shown in Appendix Table E-2.

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* Iraq, the other member of the original Gulf group, has still not signed. It has yet to reach a firm decision on the Participation Agreement which is only one of various important outstanding issues it has with the IPC Group of companies, including settlement of the Iraqi nationalization last year of Kirkuk production from IPC's northern Iraqi fields. Separate participation agreements remain to be worked out with Libya and Nigeria -- both of whom have established precedent for better than 25-per-cent initial equity.

** "Updated" book value is equal to the difference for each prior year of a concession between (i) capitalized expenditures plus all exploration and intangible development costs not capitalized, and (ii) the amount by which government revenues were reduced as a result of depreciation and amortization charges against companies' taxable income (again including fully expensed exploration and intangible development costs), times a Middle East Construction price index to bring past investment to the value of 1972 dollars.

27. The governments' equity share of crude production for each increment of participation, including the initial 25-per-cent share, is to be phased in over a 10-year period. With the initial 25-per-cent increment, governments' equity share of production is to be split into three separate categories over the first three years of the Agreement. The first category, called "bridging" crude, represents the volume of crude which governments have agreed to sell back to the companies to enable the companies to fulfill previous commitments. Bridging crude will amount to 75 per cent of governments' one-quarter share (or 18.75 per cent of total crude production) in 1973, 50 per cent (12.5 per cent of total production) in 1974, and 25 per cent (6.25 per cent of total production) in 1975, being phased out entirely in 1976.*

28. The second category, called "phase-in" crude, represents the maximum share of government crude that producing companies are obliged to buy back if governments exercise that option of putting the oil back on the companies. The phase-in option is intended to provide governments with an outlet for their oil while the countries are developing their own markets.** For the initial 25-per-cent participation, phase-in crude volumes will be equal to 15 per cent of the governments' one-quarter share (or 3.75 per cent of total production) in 1973, 30 per cent (7.5 per cent of total production) in 1974, and 50 per cent (12.5 per cent of total production) in 1975.

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* There is no bridging crude associated with increments of participation beyond the initial 25 per cent interest.

** Saudi Arabia and Abu Dhabi have reportedly elected to require the companies to purchase the maximum quantities for the first four years of the Agreement. Furthermore, this decision is partially binding for another four years thereafter -- i.e., the governments are not permitted to reduce that volume by more than 25-per-cent annually in the subsequent four years.

29. The third category of participation crude is "disposable" crude, which the governments are neither obligated to sell back nor have the option of tendering back at guaranteed prices to the concessionaries. Crude in this category could be sold back to concessionary companies, but this would presumably have to be on a normal commercial basis. Volumes of disposable crude will only be equal to 10 per cent of the governments' one-quarter share (2.5 per cent of total production) in 1973, rising to 20 and 25 per cent (5 and 6.25 per cent of total production) in 1974 and 1975 respectively. Thereafter, percentages of disposable crude will rise progressively to reach a maximum under current arrangements of 51 per cent of total production. This assumes the governments will acquire their additional equity shares within the minimum agreed-upon period.

30. Specific prices for bridging and phase-in crude were set in separate implementing agreements by each Gulf State and the appropriate companies. By way of example, prices, tax-paid cost, and average cost to producing companies of Saudi Arabian Light crude (API 34°) over the first three years of the participation agreement are set out in Appendix Table E-3.* The price of bridging crude for Saudi Arabian Light crude in 1973 was set at 19 cents per barrel above the quarter-way price (i.e., one-quarter-way between tax-paid cost and the posted price); phase-in crude was set at a flat 35 cent per barrel above tax-paid cost. This works out to a bridging price of about $2.05 per barrel and a phase-in price of about $1.97 for 1973. The average weighted cost of a company's equity crude (at tax-paid cost), bridging crude, and phase-in crude for Saudi Arabian Light would work out to around $1.72 in 1973, or about 10 cents above the tax-paid costs of a company's equity production. In order for a company to maintain an average pre-participation profit margin of about 40 cents per barrel on all barrels lifted, actual market prices would thus have to increase from the "pre-participation" level of $2.02 to about $2.12 a barrel.** While market conditions look to be conducive to the full recovery of the costs of participation, it may not be quite so automatic as in the case of higher tax-reference prices or higher tax rates, which are typically covered by contractual escalation clauses.

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* As previously discussed, the Teheran and subsequent agreements only set posted prices through 1975. Crude costs and buy-back prices beyond that date are subject to later negotiation.

** However, actual margins would tend to vary somewhat among firms depending on their particular overlift or underlift positions, as well as how each assesses the cost of replacing the governments' "disposable" crude.

31. Looking further ahead, however, the picture is not nearly so clear.* Posted prices will be open to renegotiation as from 1975; buy-back prices at least that soon, if not earlier. Participation vests governments with equity rights in production. Obviously they will expect to realize maximum value for such equity. But more important, participation vests an effective voice in decision-making with governments -- with respect to current production programs as well as forward planning for investment and capacity. In course, governments may well be in a position to capture, through negotiation over production schedules, etc., a larger share of the producing profits even on the companies' equity shares in production.

32. It is important to note that a government's profit on its equity oil can be enhanced by renegotiating upward its cents-per-barrel "add on" to quarter-way price and tax-paid cost in the case of bridging and phase-in crude, respectively. Thus, to the extent that the companies are successful in recovering the costs of participation through higher market prices, governments may look to higher buy-back prices.

33. Alternatively, governments may take the position that tax-reference prices (i.e., posted prices) should reflect any improvement in crude/product values in world markets. This could indirectly increase buy-back prices through the effect on quarter-way prices and tax-paid costs. At the same time, it would enable governments to increase their take out of the profit margin on the companies' equity crude. That is to say, while producing governments will be concerned to hold world oil prices up, they will be equally concerned that no "unnecessary" share of producing profits on their countries' crude shall accrue to the companies.

34. The longer-run outlook, given the trends that have now taken hold, is for governments increasingly to involve themselves in oil operations and oil trade. As they do, it is unlikely that the margins on companies' production can long be maintained. Not that government competition need inevitably lead to price weakness; but to the extent that government policies are conducive to continued price strength, they are likely to claim an increasing share of the profit margin -- with the weight of their concessionary participation as well as political muscle to achieve that end.

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* Section II of the main text provides a more comprehensive discussion of the uncertainties surrounding the future circumstances and costs of Middle East crude production.

Footnotes to Table

a Assumes no escalation for further changes in currency exchange rates.

b Includes 3.4¢ freight premium; excludes any penalty in the reference price for variations above and below base export volumes.

c Includes temporary premium for Suez Canal closure (13¢).

d Includes 9.8¢ retroactive "buy out" payments.

e Base posted price less harbor dues.

f Royalty based on posted price less 10¢ gathering charge deduction to determine wellhead value. Includes 6¢ harbor dues.

g Includes 2¢ net cost of harbor dues.

TABLE E-1
FOB POSTED PRICES AND TAX-PAID COSTS OF SELECTED FOREIGN CRUDE OILS, 1970, 1973 AND 1975

(Dollars Per Barrel)

	Posted Prices			Tax-Paid Costs		
	July 1970	January 1973	January 1975[a]	July 1970	January 1973	January 1975
Venezuelan Oficina (35°) (Tax-Reference Price)	2.80 (2.34)	2.80 (3.40)[b]		1.70	2.43	
Venezuelan Tia Juana Med. (26°) (Tax-Reference Price)	2.30 (2.00)	2.30 (3.09)[b]		1.51	2.24	
Venezuelan Lagunillas (16°) (Tax-Reference Price)	2.07 (1.65)	2.07 (2.80)[b]		1.32	2.04	
Libyan (40°)	2.23	3.78[c]	4.10[c]	1.41	2.52[d]	2.72[d]
Nigerian Light (34°)	2.11[c]	3.56[c]	3.89[c]	1.38[f]	2.38[g]	2.58[g]
Saudi Arabian Lt. (34°)	1.80	2.59	2.82	1.02	1.62	1.76
Kuwait (31°)	1.59	2.48	2.71	.89	1.53	1.67

Notes: Tax-paid costs are based on the following -- (i) producing costs - Venezuela (51¢ in 1973 and 50¢ in 1970), Libyan (30¢), Nigerian (45¢), Saudi Arabia (11¢), Kuwait (6¢); (ii) royalty rates - 16-2/3% in Venezuela and 12.5% in Eastern Hemisphere; (iii) royalty values - in Venezuela, $3.29 in 1970 and $3.54 in 1972 for Oficina, $3.11 and $3.36 for Tia Juana Med.; $3.00 and $2.85 for Lagunillas; posted price in Eastern Hemisphere; (iv) income tax price - in Venezuela, tax-reference price as shown above; in Eastern Hemisphere, posted price, except posted price less OPEC allowance in Nigeria, Saudi Arabia, and Kuwait in 1970; (v) income tax rate - in Venezuela, 50% in 1970 and 58% in 1973; in Eastern Hemisphere, 50% in 1970 and 55% in 1973 and 1975.

TABLE E-2
GOVERNMENTS' SHARE OF TOTAL CRUDE PRODUCTION UNDER PARTICIPATION, 1973-1992

(Per Cent)

	Total	Bridging	Phase-In	Disposable
1973	25	18.75	3.75	2.50
1974	25	12.50	7.50	5.00
1975	25	6.25	12.50	6.25
1976	25		17.50	7.50
1977	25		16.25	8.75
1978	30		19.50	10.50
1979	35		21.00	14.00
1980	40		22.25	17.75
1981	45		20.28	24.72
1982	51		22.40	28.60
1983	51		18.30	32.70
1984	51		16.75	34.25
1985	51		14.95	36.05
1986	51		12.90	38.10
1987	51		10.10	40.90
1988	51		7.00	44.00
1989	51		4.40	46.60
1990	51		2.30	48.70
1991	51		0.60	50.40
1992	51		...	51.00

Notes: (i) Total government share assumes all cash installments are paid on time and that all notices to acquire additional equity are made on time, so that full 51-per-cent participation is reached by 1982.

(ii) Phase-in percentages are maximums that could be tendered back to the companies. From 1976 on, the percentages of phase-in crude shown above would be applied only to the total quantity of crude produced in a concession in 1975. So if production goes on rising after 1975, phase-in quantities would actually be a lower percentage than shown above of total crude output in subsequent years.

(iii) Disposable percentages are remaining shares of production that the governments are neither obligated to sell back (bridging crude) nor have the option of tendering back (phase-in crude). From 1976 on, the percentages of disposable crude shown above will be applied only to the volume of crude production attained in 1975. Governments will have as disposable crude their full equity share of all subsequent increments of new production. In such case, a government's volume of disposable crude would be a higher percentage than shown above of total crude production in subsequent years.

TABLE E-3

PRICES, TAX-PAID COST, AND AVERAGE COST OF SAUDI ARABIAN LIGHT CRUDE (34°) TO COMPANIES UNDER PARTICIPATION, 1973-1975

(Dollars per Barrel)

	1975	1974	1973
Posted Price[a]	2.82	2.71	2.59
Tax-Paid Cost of Equity Crude	1.76	1.69	1.62
Bridging Price	2.22	2.14	2.05
(Margin over Tax-Paid Cost)	(.46)	(.45)	(.43)
Phase-In Price	2.11	2.04	1.97
(Margin over Tax-Paid Cost)	(.35)	(.35)	(.35)
Average Cost of Equity, Bridging, and Phase-In Crudes	1.84	1.78	1.72
(Margin over Tax-Paid Cost)	(.08)	(.09)	(.10)
Reported Market Price			2.02[b]
(Margin over Tax-Paid Cost)			(.40)

Note: All costs are per barrel of crude lifted by companies: equity -- 75 per cent of total production; equity plus bridging plus phase-in -- 97.5 per cent in 1973, 95 per cent in 1974, and 93.75 per cent in 1975.

[a] Posted price assumes no further escalation for currency exchange rates.

[b] Reported price range in late December 1972 for 1973 delivery is $2.01-$2.03. Includes January 1973 royalty/income tax escalation, but no allowance for cost of participation.

APPENDIX F

PRODUCTION AND SEVERANCE TAXATION IN MAJOR PRODUCING STATES OF THE U.S.

1. Rates of taxation on oil and gas production in various states of the United States are of significance for Alberta because Alberta production, now and in the future, must meet and compete with U.S. resources in U.S. markets. This is not to say that Alberta's total "take" from hydrocarbons production -- royalties plus taxes on reserves -- must parallel that in the United States. As will be seen, taxes on production differ substantially among various U.S. producing states. And there are special conditions of oil operations and of land tenure in Alberta that would also bear importantly upon the Province's royalty and tax policies. Nonetheless, a substantial part of Alberta production will be moving to U.S. markets, so that relative costs, including taxes on production levied by various states, would be of significance for the competitive capabilities and profitability of Alberta's hydrocarbon resources.

2. Virtually all important oil and gas producing states in the United States impose what are commonly called production or severance taxes. These taxes are based either on the value of production or the number of units produced. The major exception is California; but in this State, production is subject to taxes imposed by various local governments. This Appendix briefly summarizes the nature and incidence of taxation on oil and gas production in the major producing states of the United States.

3. The terms "production tax" and "severance tax" are generally used interchangeably and usually refer to taxes on production clearly intended as general revenue-raising measures. For convenience, these taxes are hereafter referred to as severance taxes. Many states also impose an oil and gas "conservation" tax -- i.e., a levy on oil and gas production designed primarily to cover the expenses of a state oil and gas conservation board or similar regulatory body.* As compared with severance taxes, conservation taxes tend to be a relatively minor tax on producing operations.

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* In the case of California, this is the only tax levied by the State Government on production.

4. The overall burden of severance taxes on oil and gas producing operations in the various states depends importantly on provisions, if any, for abeyance of state and local ad valorem property taxes. In many states, the production tax is in lieu of ad valorem taxes on producing properties -- e.g., on property rights, leases, and equipment used in producing operations.* In other states, production taxes are in addition to ad valorem property taxes. Thus, the relative tax burden on producing operations among states can be assessed only by considering the impact of severance taxes, or property taxes, or a combination of the two.

5. Table F-1 summarizes the basic provisions of oil and gas severance taxes in major producing states.** The tabulation includes provisions with respect to --

Tax rates;

Tax bases;

Provisions for abeyance of other taxes; and

Local provisions for severance taxes.

To provide a complete picture, conservation taxes are also included.

6. Two things stand out in a first look at taxes on oil and gas production in the major producing states:

There is a wide variation among the states as to all of the major provisions; and

A number of states have multiple taxes on oil and gas production.

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* A major argument for a severance tax in lieu of a property tax is that it represents an easier and more equitable means of taxing the value of producing properties.

** The tabulation includes all states with current crude production in excess of 50,000 barrels daily.

7. The multiplicity of taxes within states is owing to several factors. First, as noted above, a relatively large number of states have enacted separate levies to finance the operations of state agencies that are charged with regulating the oil and gas industry. These conservation taxes are generally related at least indirectly to actual expenditures of these agencies.

8. In cases where multiple severance taxes exist, the second (and even third) taxes usually represent taxes enacted to meet special revenue needs as of a particular time. Thus, for example, among the four separate taxes on production in New Mexico (of which one is a conservation tax) is a 2.55 per-cent tax "for emergency school purposes," originally passed in the late 1930's.

Tax Bases and Rates

9. There are basically two different ways in which severance taxes are imposed:

Taxes which are a percentage of the value of production; and

Taxes which are so many cents or mills per unit of production.

A number of states which have more than one tax on production use both types of taxes. And some tax laws specify that the tax on production shall be the higher of either a percentage of value or a per-unit rate.

Value of Production

10. Among severance taxes, those imposed as a percentage of value are most common.* Of the twelve major producing states that have severance taxes, seven have taxes directly based upon gross value of production --

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* In contrast to severance taxes, most conservation taxes are on a unit basis. This is basically because the intent of these taxes is to collect a certain specific amount of revenue -- i.e., that necessary to meet the expenses of a conservation board. These expenses, or an estimate of these expenses, are then divided by the total volume of production -- or expected production -- to arrive at a per-unit levy.

Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. Another two states -- Texas and Mississippi -- have taxes based on the higher of a unit or percentage tax, but the minimum taxes per unit of production are so low that in practice the taxes are computed as a per cent of value of production.* The only large producing state with a severance tax on a unit-of-production basis is Louisiana. The severance tax in Kansas is also on a unit basis, but the rate of tax is so low that the severance tax is only a very minor revenue-raising measure.**

11. The Alaskan oil severance tax is based on the higher of a percentage-of-value or per-barrel levy. The way the tax is structured, the percentage-of-value tax is effective when the wellhead value of oil exceeds $2.65 per barrel. At wellhead prices below $2.65 per barrel, the per-barrel tax is applicable. In addition to being a taxing authority, the State of Alaska is also a major landowner and thus derives revenue from production both in the form of royalties and severance taxes. In the event that wellhead prices are below $2.65 per barrel, the per-barrel severance tax is designed to yield the State the same total per-barrel revenues from royalty and severance tax combined that would be forthcoming if the wellhead price were $2.65 per barrel. The per-barrel tax rates are set at levels which are equivalent to the State's total per-barrel revenues from severance taxes and royalties at a wellhead price of $2.65, with royalty payments deductible from these tax rates to arrive at actual severance taxes payable. Thus, as prices fall below $2.65 and royalties (normally 12.5 per cent of the value of production) decline, severance taxes would automatically increase to offset the decline in royalty income brought about by lower prices.***

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* In Texas, for example, the tax on oil is 4.6 cents or 4.6 per cent if the market value exceeds $1.00 per barrel. For some time, there have been no wellhead crude-oil prices posted in Texas below about $3.00 per barrel.

** Current receipts from oil and gas severance taxes in Kansas are on the order of $600,000 per year. However, property taxes on producing operations in Kansas are relatively high.

*** For example, the Alaskan severance tax on a 300-barrel-per-day well is the higher of 3 per cent of wellhead value or 45.8 cents per barrel less royalty payments. At a price of $2.65 per barrel, these two tax rates are equivalent -- i.e., 3 per cent times 87.5 per cent of $2.65 (severance taxes are not payable on the 12.5 per cent state royalty portion of the barrel) would yield a severance tax of 6.96 cents per barrel; alternatively, 45.8 cents per barrel times 87.5 per cent (40.08 cents) less royalty of 33.12 cents (12.5 per cent of $2.65) would also yield 6.96 cents in severance tax. At a $2.00 per-barrel price, the 3-per-cent tax rate would yield 5.25 cents per barrel; the per-barrel tax would yield 15.08 cents. The latter would be the operative tax and combined with a royalty of 25 cents would yield that State the same total revenue as on a $2.65 price. At a price of $3.00 per barrel, the percentage tax would be 7.9 cents per barrel and the per-barrel tax 2.6 cents per barrel; thus the percentage-of-value tax would be operative.

12. Where taxes are based on value, it is usually gross value of production at the wellhead, including royalty interests. There are, however, some minor variations --

> The tax in Colorado is on gross income from production of oil and gas, which could differ somewhat from wellhead value where sales are made beyond the wellhead.
>
> One of New Mexico's severance taxes allows a deduction of 50 per cent of the wellhead value as an allowance for production costs.

Any part of the value of production accruing to tax-exempt organizations -- including the State government itself and the Federal government -- is usually deducted in computing the tax base.

13. Where severance taxes are a per cent of value, the statutory rate on oil[*] ranges from 1 per cent in Wyoming[**] to 8 per cent in Alaska (on production from wells in excess of 2,500 barrels daily, of which more below). (See Table F-2.) The median and most common tax rate is 5 per cent. The rate in Texas, the Nation's leading producing state, is 4.6 per cent; but the severance tax in Texas is in addition to ad valorem property taxes, whereas in many other states it is in lieu of property taxes (of which more below).

14. Three states have progressive tax rates on value[***] --

> In Colorado, the rate increases in four steps from 2 per cent on annual gross income from production under $25,000 to 5 per cent on gross income over $300,000.

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[*] We consider severance taxes on gas production later.

[**] The net severance tax rate in Wyoming is 1 per cent. The gross rate is 6.25 per cent, against which a credit of 5.25 per cent is allowed for ad valorem tax on oil-lease property based on preceding years' gross production.

[***] And in Utah, the rate is 2 per cent, but with an exemption for the first $50,000 of production per designated field.

> In Montana, the rate is 2.1 per cent on the first 450 barrels of production each quarter and 2.65 per cent on the excess over 450 barrels.
>
> In Alaska, the rate increases in four steps from 3 per cent on the first 300 barrels of average daily production for each well to 8 per cent on all production in excess of 2,500 barrels per day.

In Colorado and Montana, the highest tax rate would be effective at relatively modest levels of production. Thus, sliding-scale rates in these two states would seem to be designed primarily to give some measure of tax relief to relatively small producers.

Unit of Production

15. As noted, Louisiana and Kansas have severance taxes expressed as cents per unit of production. In Louisiana, the tax on crude oil increases in seven steps according to the gravity of oil -- from 18 cents per barrel on oil of 22° (API) gravity and below to 26 cents per barrel for oil above 43° gravity.* Production from wells incapable of producing more than an average of 6 barrels daily is taxed at one-half of these scheduled rates. In Kansas, the severance tax on oil is a modest 1/10 of a cent per barrel.

16. As discussed above, Alaska has a cents-per-barrel severance tax on oil which becomes effective when the wellhead value of oil is below $2.65 per barrel; at values above $2.65, a percentage-of-value tax is applied. The unit-of-production tax increases in four steps, from 45.8 cents per barrel on the first 300 barrels of average daily production for each well to 59.1 cents on all production in excess of 2,500 barrels per day.** However, royalty payments (up to one-eighth of the value of oil produced) are deductible from these rates. Thus,

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* Separate rates are set for natural gas liquids -- 20 cents per barrel for condensate and 2 cents per barrel for natural gasoline or casinghead gasoline.

** These rates are applicable on production before July 1, 1980. On or after July 1, 1980, the rates are reduced to a range of 43.2 cents per barrel in lowest bracket to 55.7 cents in the highest bracket.

actual severance tax payments under the per-barrel tax alternative would be substantially less than the statutory rates. At a wellhead price of $2.00, for example, severance tax payments would range from 15.1 cents per barrel on the first 300 barrels daily of well production up to 26.7 cents on well production in excess of 2,500 barrels per day.

Gas Severance Tax Rates

17. In the majority of producing states, the same percentage rate of taxation applies to both oil and natural gas production. However, the two largest producing states -- Texas and Louisiana -- assess different rates on oil and gas. In both states, the tax rate is higher on gas:

> In Texas, the tax is 4.6 per cent on oil as against 7.5 per cent on gas;*
>
> In Louisiana, the statutory unit tax rates work out to a higher percentage rate of tax on the value of oil than gas -- in the range of 6.5 to 7 per cent on crude oil and around 16 per cent on natural gas (of which more later).

The higher rates of severance taxation on the value of gas as against oil in these two states is probably owing basically to the earlier historical circumstances of natural gas production -- when gas reserves had been found primarily as a by-product of oil exploration and only later did large-scale commercial gas production get underway, with the development of major trunk pipelines and distribution networks.

18. In Alaska, the severance tax on natural gas is a flat 4 per cent of wellhead value. This compares with a range of 3 to 8 per cent on oil production, depending upon well productivity.

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* These rates apply above certain minimum levels of payment per unit -- 4.6 cents per barrel of oil and 121/1,500 cent per MCF of gas.

Other Taxes on Producing Operations

19. The relative burden of severance taxes in various states cannot really be evaluated without considering other taxes on production -- ad valorem property taxes and local taxes on production.

20. Provisions regarding abeyance of state and/or local ad valorem property taxes on oil and gas producing operations vary considerably. In a number of states -- Alaska, Colorado,* Louisiana, Mississippi, North Dakota, and Oklahoma -- the severance tax is in lieu of ad valorem property taxes on producing properties. However, among these states, there are differences in the scope of property which is exempt from ad valorem taxes. In North Dakota, the tax is in lieu of all ad valorem taxes on property rights, leases and machinery and equipment used in and around producing wells. The tax laws in Mississippi and Oklahoma have similar, wide-range definitions of producing property not subject to ad valorem taxes.** But in some other states, the exemption from ad valorem taxes applies to a narrower range of property --

> In Alaska, severance taxes are in lieu of all ad valorem taxes on property rights and leases except machinery, appliances and equipment used in and around a producing well and used in the operation of the well;
>
> In Louisiana, the law provides only that no additional tax can be levied on oil and gas leases, nor can any additional value be added to assessment of land by reason of presence or production of oil or gas;

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* In Colorado, the tax is not actually in lieu of ad valorem taxes, but a credit is allowed against the severance tax for certain ad valorem taxes paid (of which more later).

** However, it does not appear that any of the states provide that severance taxes shall be in lieu of ad valorem taxes on property and equipment used in oil operations beyond the producing area -- e.g., trunk pipelines, terminal facilities for loading oil onto tankers, etc.

> In Colorado, a credit is allowed against the severance tax for ad valorem taxes on petroleum leaseholds and royalty interests, but not for ad valorem taxes paid on equipment and facilities used in drilling, production, storage, pipelining, etc.

21. In contrast, in a number of other states, tax laws either specifically provide that the severance tax is in addition to ad valorem property and other taxes -- Montana and Wyoming -- or have no provisions with regard to abeyance of other taxes -- Kansas, New Mexico and Utah. Thus, in these states, ad valorem property taxes can add significantly to the total tax burden on producing operations. In most states, property taxes are levied primarily by local jurisdictions -- counties, school districts, municipalities, etc. As a result, the level of property taxes tends to reflect the fiscal needs of these jurisdictions and can often vary considerably from locality to locality. Thus, the extent to which oil and gas production may be subject to ad valorem property taxes in the above states would depend on where the production is located within the state.

22. One major producing state, California, does not have a state-wide severance tax. But producing operations in California can be and often are subject to fairly high ad valorem property taxes. In addition -- and in contrast to other states -- various local municipalities in California impose special taxes on oil and gas production. These local production levies take various forms, including per-barrel charges, per-well charges, and flat fees. The Western Oil and Gas Association estimates that all state and local taxes on crude oil production in California currently amount to approximately 6.8 per cent of the gross value of production.

23. Texas, the leading producing state, has a severance tax on oil production of 4.6 per cent. However, in Texas, the severance tax is in addition to ad valorem taxes levied on all real property, including mineral rights and privileges. While varying considerably among various localities, indications are that over the State as a whole, ad valorem taxes on producing properties might average close to 3 per cent of the value of oil and gas production. On this basis, the total burden of taxation on oil production in Texas -- including both severance and property taxes -- could be on the order of 7.5 per cent of the value of production. For gas production, the total burden could work out to around 10 1/2 per cent -- 7.5 per cent severance tax, together with ad valorem property tax.

24. In Louisiana, the second largest producing state, the per-barrel severance tax on crude oil amounts to about 6.5 to 7 per cent of wellhead value, based on posted prices. In Louisiana, estimated ad valorem taxes on equipment, facilities, etc. used in production amount to around 0.6 per cent of value of oil production. Thus, the total burden of state and local taxes on oil production in Louisiana is about 7 to 7.5 per cent of value. For natural gas, the per unit tax currently amounts to about 16 1/2 per cent of the value of natural gas production. With the addition of ad valorem taxes, the total tax burden on gas production would be around 17 per cent of value of production.

25. In Oklahoma, where the severance tax is in lieu of ad valorem property taxes, the severance tax on both oil and gas production is 7 per cent. In Alaska, a well producing 10,000 barrels of oil daily (an estimate of the average well productivity in the main producing reservoir of Prudhoe Bay) would incur severance tax in the neighborhood of 7 to 7.5 per cent of the value of production.* On gas, Alaskan severance tax payments would be 4 per cent of the value of production.

26. In sum, provisions for oil and gas severance taxation vary greatly among major producing states in the United States. The relative burden of severance taxes in various states must also take into account other taxes on production -- ad valorem property taxes and local taxes on production. In the four largest producing states -- Texas, Louisiana, California, and Oklahoma -- which account for four-fifths of total U.S. crude production, the rate of state severance and/or property taxation works out to around 7 to 8 per cent of the value of crude oil production. The rate of taxation in Alaska, which will become a major producing State when production begins from Prudhoe Bay, is in the same range.*

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* This assumes wellhead values of $2.65 or greater. If wellhead values fall below $2.65, the effective rate of severance tax would increase above this level.

TABLE F-1

PRODUCTION AND SEVERANCE TAXES IN MAJOR PRODUCING STATES, JANUARY, 1973

State	Tax Rate	Tax Base	Provisions for Abeyance of Other Taxes	Local Provisions
Alaska	On oil, the greater of: 3% on first 300 barrels of average daily production for each well, 5% on next 700 barrels, 6% on next 1,500 barrels and 8% on all in excess of 2,500 barrels; or 45.8¢ per barrel on the first 300 barrels of average daily production for each well, 51.1¢ on the next 700 barrels, 53.8¢ on the next 1,500 barrels and 59.1¢ on all production in excess of 2,500 barrels, less royalty value up to one-eighth.	Gross value of production at the wellhead or barrels removed or sold from each lease.	In lieu of all ad valorem taxes on property rights and leases, except machinery, appliances and equipment used in and around a well and in its operation.	No provision respecting local severance taxes.
	On gas, 4% of value of gas and liquid products produced.	Gross value of production at the wellhead.		
California	Annual levy to support offices of oil and gas supervision (in 1968, 0.265¢ per barrel of oil and 0.265¢ per 10 MCF of gas); plus Additional annual charge in subsidence area (in 1968, 0.142¢ per barrel of oil or 0.142¢ per 10 MCF of gas in Wilmington field).	Allocated on basis of barrels of oil and cubic feet of gas produced.	In addition to all other charges and taxes.	Various local municipalities impose taxes on producing operations. Loca levies include per-barrel charges, per-well charg and flat fees.

TABLE F-1 (Cont'd)

PRODUCTION AND SEVERANCE TAXES IN MAJOR PRODUCING STATES, JANUARY, 1973

State	Tax Rate	Tax Base	Provisions for Abeyance of Other Taxes	Local Provisions
Colorado	2% under $25,000; 3% on $25,000-99,999; 4% on $100,000-299,999; and 5% over $300,000[a]; plus	Gross income from production of oil and gas.	Credit against tax on gross income is allowed for all ad valorem taxes paid upon petroleum leaseholds and royalty interests for state and local purposes (but excluding ad valorem taxes paid upon equipment and facilities used in drilling, production, storage, pipelining, etc.)	No provision respecting local severance taxes.
	0.1% on oil and gas (conservation tax)	Market value of production at the well.		
Illinois	No tax. Statute imposing a tax on oil production enacted in 1941 held to be unconstitutional and repealed in 1959.			
Kansas	0.1¢ per barrel of oil (State Health Board tax); plus	Barrels of production purchased by first purchases.		No provision respecting local severance taxes.
	0.001¢ per barrel of oil.	Barrels of crude oil or petroleum marketed or used.		
	0.005¢ per MCF of gas; plus	Cubic feet produced.		
	0.05¢ per MCF of gas.	Cubic feet marketed.		
Louisiana	18¢ per barrel on oil of 22° (API) gravity and below; 20¢ for above 22° to 28°; 21¢ for above 28° to 31°; 22.5¢ for above 31° to 32°; 24.5¢ for above 32° to 36°; 25¢ for above 36° to 43°; 26¢ for above 43°. Wells incapable of producing more than average of 6 barrels daily, one-half of scheduled fees.	Barrels severed from soil or water.	No further or additional tax or license can be levied upon oil or gas leases, nor can any additional value be added to assessment of land by reason of presence or production of oil or gas.	Local severance taxes prohibited.

TABLE F-1 (Cont'd)

PRODUCTION AND SEVERANCE TAXES IN MAJOR PRODUCING STATES, JANUARY, 1973

State	Tax Rate	Tax Base	Provisions for Abeyance of Other Taxes	Local Provisions
Louisiana	20¢ per barrel of distillate, condensate, or other similar natural resources.	Barrels severed from soil or water either with oil or gas.		
	2¢ per barrel of natural gasoline or casinghead gasoline.	Barrels severed.		
	3.3¢ per MCF of gas, except 2.3¢ per MCF if wellhead pressure is 50 lbs. per sq. inch or less or if wells are incapable of producing 250 MCF per day.	Cubic feet severed.		
Mississippi	6¢ per barrel or 6% on oil, whichever is higher.	Barrels produced or value at the point of production.	All oil and gas produced and under the ground and all equipment used in producing oil and gas is exempt from state and local ad valorem taxes.	No provision respecting local severance taxes.
	0.3¢ per MCF or 6% on gas, whichever is higher.	Cubic feet produced or value at the point of production.		
	Maintenance charge to support Oil and Gas Board, not to exceed 0.2¢ per barrel of oil and 0.01¢ per MCF of gas.	Barrels of oil produced or saved; cubic feet of gas produced.		
Montana	2.1% on first 450 barrels produced each quarter and 2.65% of excess over 450 barrels (license tax) on persons engaged in oil production; plus	Gross value of oil production at the wellhead.	License tax on production is in addition to all taxes and other fees.	No provision respecting local severance taxes.
	Conservation tax, currently 0.25¢ per barrel of oil on wells producing 25 barrels daily or less and 0.5¢ per barrel on wells producing more than 25 barrels per day and 0.1¢ on each 10 MCF of gas.	Barrels of crude produced, saved, marketed, or stored within the state, or exported; cubic feet of gas produced.		

TABLE F-1 (Cont'd)

PRODUCTION AND SEVERANCE TAXES IN MAJOR PRODUCING STATES, JANUARY, 1973

State	Tax Rate	Tax Base	Provisions for Abeyance of Other Taxes	Local Provisions
New Mexico	2.5% on oil and gas (severance tax); plus 0.14% on oil and gas (conservation tax); plus 2.55% on oil and gas (emergency school tax); plus Ad valorem production tax, at local ad valorem rate.	Taxable value -- price received at the production unit less royalties paid to the U.S., New Mexico, and Indians and expense of transporting to first place of market. For ad valorem production tax, there is an additional deduction of 50% of the remaining balance as an allowance for production costs.		Local severance taxes are prohibited.
North Dakota	5% on oil and gas.	Gross value at the well, including royalty interest (but excluding any part of the value the ownership or right to which is tax exempt).	Production tax is in lieu of all ad valorem taxes by state or any of its subdivisions upon property rights, leases, and producing equipment utilized in oil and gas operations.	No provision respecting local severance taxes.
Oklahoma	7% on oil and gas (gross production tax); plus 0.21875¢ per barrel of oil and 0.04¢ per MCF of gas (excise tax).	Gross value at time and place of production. Barrels of oil and cubic feet of gas produced.	Production tax is in lieu of all taxes by the state or any of its subdivisions upon mineral property rights, producing leases, and land, equipment, etc. actually used in the operation of a well.	See provisions for abeyance of other taxes.

TABLE F-1 (Cont'd)

PRODUCTION AND SEVERANCE TAXES IN MAJOR PRODUCING STATES, JANUARY, 1973

State	Tax Rate	Tax Base	Provisions for Abeyance of Other Taxes	Local Provisions
Texas	4.6¢ per barrel of oil or 4.6% if market value exceeds $1.00 per barrel; 7.5% on natural gas, but not less than 0.08067 (121/1500)¢ per MCF on natural gas (occupation tax); plus	Barrels of oil produced or market value; value of gas as and when produced.	Occupation tax is in addition to ad valorem taxes, which are levied on all real property, including mineral rights and privileges.	No subdivision may levy an occupation tax unless specifically permitted to do so by the legislatur
	0.1875¢ per barrel of crude petroleum (conservation tax).	Barrels of crude petroleum produced.		
Utah	2% on oil and gas, with an exemption for the first $50,000 production per designated field; plus	Value at the well.		No provision respecting local severance taxes.
	Oil and gas conservation tax, not to exceed 0.2¢ per dollar (current rate is 0.15¢).	Value at the well of all oil and gas produced and saved, sold or transported from the premises.		
Wyoming	1% on oil and gas (severance tax);[b] plus	Value at the well of all oil and gas produced, saved and sold or transported from the premises.	In addition to the net severance tax, there is an ad valorem tax on oil lease property based on preceding years' gross production (see ftn. b).	No provision respecting local severance taxes.
	Oil and gas conservation tax, not to exceed 0.04¢ per dollar (current rate is 0.03¢).			

Note: Tabulation includes all states with crude production in excess of 50,000 barrels daily. In total, the fourteen states above account for some 95 of total U.S. crude production.

[a] Tax on gross income from oil aid gas production is part of Colorado state income tax law, but is in addition to tax on net income.

[b] Net severance tax rate is 1%. Gross rate is 6.25%, against which a credit of 5.25% is allowed for ad valorem tax on oil-lease property based on preceding years' gross production (in lieu of taxes on the land, but in addition to a tax on surface improvements). This ad valorem tax has been held to be a tax on property and not a privilege tax.

TABLE F-2

RATE OF TAX ON OIL PRODUCTION
IN STATES WHERE TAX IS ON VALUE, JANUARY, 1973

(Per Cent)

Alaska	3.0 - 8.0[a]
Colorado	2.0 - 5.0
Mississippi	6.0
Montana	2.1 - 2.65
New Mexico	5.05 +[b]
North Dakota	5.0
Oklahoma	7.0
Texas	4.6
Utah	2.0
Wyoming	1.0[c]

Note: Excludes conservation taxes.

[a] In Alaska, percentage rates only apply when wellhead values are above \$2.65 per barrel.

[b] Rate in New Mexico is 5.05 per cent plus a tax on the value of production (less 50 per cent deduction for costs) at local ad valorem property tax rates.

[c] In Wyoming, the gross rate is 6.25 per cent, against which a credit of 5.25 per cent is allowed for ad valorem tax on oil-lease property.